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FINAL REPORT

ASSESSMENT OF EMISSION CONTROL TECHNOLOGY FOR SULFUR DIOXIDE, PARTICLES, AND TRACE ELEMENTS IN FLUE GAS FROM LARGE COAL FIRED POWER PLANTS

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I. INTRODUCTION AND SUMMARY

This report contains the results of three independent studies on present-day emission control technology for coal fired plants. Each study was directed at the emission characteristics of proposed Colstrip Units 3 and 4. These 700 MW units will burn Rosebud and McKay low sulfur coal. The first study (Part II) evaluated the status of sulfur dioxide emission control and was done by Battelle-Columbus Laboratories. The second study (Part III) evaluated the status of flyash removal technology, and the third study (Part IV) investigated trace element emissions. The latter two studies were done by Battelle-Northwest.

The general methodology of the first two studies was to review the latest literature pertaining to the topic, to contact leading vendors of the modern processes, and to contact recent users of these processes for their personal experience. Then the capability of pertinent processes was evaluated with respect to the requirements of Colstrip Units 3 and 4. The methodology of the trace element study was to examine the flue gas after sulfur dioxide and flyash removal and estimate the amounts of remaining trace elements.

The Sulfur Dioxide Emission Control Technology Study discusses the reliability and efficiency of available processes, considers the problems associated with stack gas reheat and sludge disposal, relates Rosebud and McKay coal properties to SO_2 removal, and critically analyzes the apparent choice of the Colstrip utilities for SO_2 control. Similar to that of Colstrip Units 1 and 2, this choice is a wet venturi scrubber that uses the ash alkalinity to provide SO_2 scrubbing capability. Only about 50% of the SO_2 initially present must be removed for emission standards to be met. A scrubber using water alone cannot accomplish this, but the flyash suspended in the scrubber feedwater along with some additional lime can, but only if the scrubber droplets are given sufficient time to contact the dirty flue gas upstream from the venturi throat. This is accomplished by having a large gas holdup volume between

the venturi and the mist eliminator. Besides the above scrubber, stack gases can be cleaned of SO_2 by several other throwaway wet and dry processes using alkali, lime or limestone, and nahcolite. Sulfur can also be recovered by a number of processes mentioned in the following section. Cost of installing a SO_2 removal system ranges from $40 to $70 per kilowatt, and operating costs range from one to three mills per kilowatt-hour.

In the State-of-Art of Flyash Removal Study, we concluded that only three basic technologies exist today that can be considered as adequate for removing flyash. These are electrostatic precipitation (hot and cold), baghouse filtration, and high energy (venturi) wet scrubbing. Based on Colstrip coal analyses, about 99% of airborne flyash must be removed to just meet the Federal Emission Standards of 0.1 grain/10^6 Btu. A safety factor of two raises the required removal efficiency to 99.5%. Baghouse filter systems and hot and cold precipitators can be designed and operated to get this efficiency. Pilot plant data for scrubbers on Colstrip Units 1 and 2 only attained 99% efficiency at one-half normal flyash loadings (Losses apparently occurred upstream of the pilot plant). If the missing half of the normal loading was composed of particles larger than about 4 micron, then the Colstrip scrubbers could expect to operate at 99.5% efficiency. With this expected efficiency and coupled with the capability to remove adequate sulfur dioxide, the choice of a venturi scrubber seems quite attractive. However, impending future regulations on submicron particle emissions is some cause for concern. Today, the most efficient process on submicron particles per dollar of capital expenditure is the baghouse filter.

In the Trace Element Study both particulate and gaseous potential emissions are estimated from available coal analyses and respective cleanup efficiencies of electrostatic precipitators, baghouses, and venturi scrubbers. No large differences in particle emission characteristics exist between the three particle removers. However, only venturi scrubbers are assumed to be able to remove 50% of the gaseous elements.

The unremoved 50% of the toxic gaseous emissions are estimated to be the following from burning 7000 tons/day of coal: 17.5 lb of arsenic, 0.9 lb of cadmium, 12 lb of copper, 15 lb of fluoride, 1.3 lb of mercury, 19 lb of lead, 5.6 lb of selenium, and 14 lb of vanadium released per day. If one percent of the flyash escapes collection, the following emissions are estimated: 0.35 lb of arsenic, 0.02 lb of cadmium, 1.2 lb of copper, 0.03 lb of mercury, 0.4 lb of lead, 0.07 lb of antimony, 0.11 lb of selenium, and 1.1 lb of vanadium released as particulates each day.

II. SULFUR DIOXIDE EMISSION CONTROL TECHNOLOGY

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II. SULFUR DIOXIDE EMISSION CONTROL TECHNOLOGY

A. Available Processes

The ideal SO_2 control process is one that gives adequate emission control without increasing the cost of electric power or steam, avoids cooling of the stack gas with consequent loss of plume buoyancy, and gives an easily storable, concentrated, and saleable product with a stable and attractive market. Such an ideal is probably impossible to attain and generally there must be some economic trade-offs between process costs and by-product income or waste-disposal costs. A major division in SO_2 removal technologies is between recovery of SO_2 in useful form and formation of a solid waste. Throwaway methods may convert an air-pollution problem to a water-pollution or solid-waste-disposal problem, while recovery methods require the marketing of a chemical product. Both the throwaway and recovery methods can be carried out in either wet or dry systems. Dry-removal systems generally do not require stack-gas reheat as wet systems may and, in some cases, can also remove particulate matter. Wet systems can remove particulate matter and SO_2 simultaneously.

The technologies for SO_2 removal are shown summarized in Figure 1.(1) A myriad of processes have been proposed and more than 50 individual processes are commonly known in the United States. Some processes are "add-on" types. These can be installed at a point where the gas had passed through all the equipment and is about to enter the stack. Another type requires higher temperature and usually is inserted ahead of the air heater. For retrofit, this involves the cost and time for cutting into the gas train, resizing or eliminating the precipitator, plus the introduction of uncertainties regarding the effects on primary plant operation. Thus, add-on types are more apt to be considered for existing plants.

Six processes have gained some degree of user acceptance in the United States. These are(2)

(1) Wet lime/limestone scrubbing

(2) Alkali scrubbing without regeneration

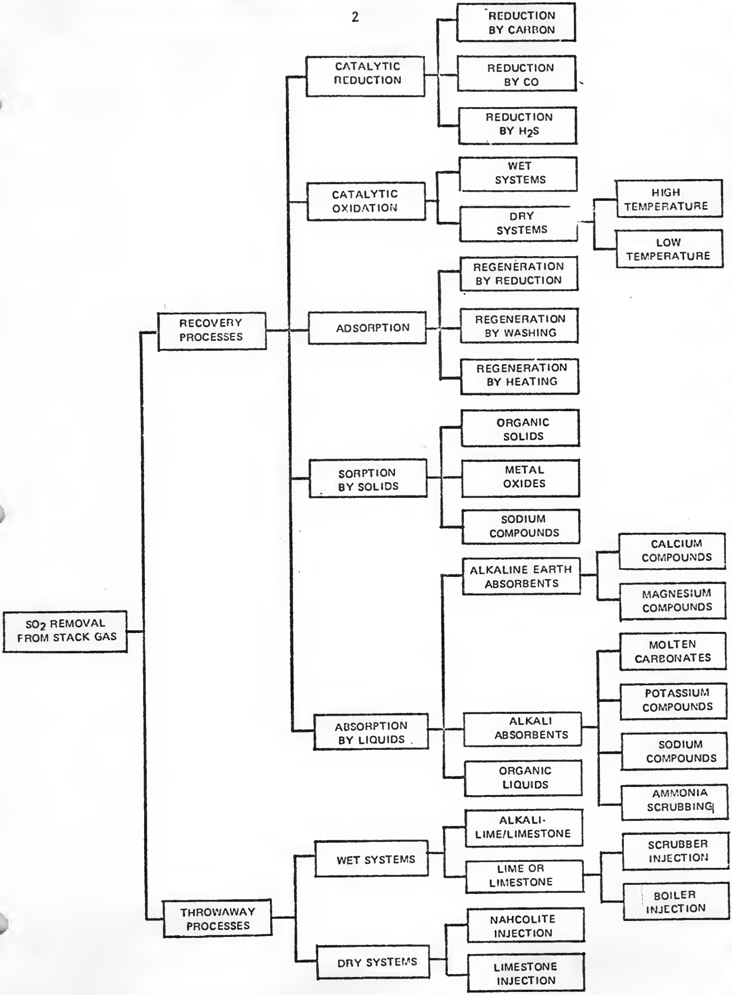

FIGURE 1. TECHNOLOGIES FOR THE REMOVAL OF SO_2 FROM STACK GAS

(3) Alkali scrubbing with calcium regeneration

(4) Alkali scrubbing with thermal regeneration

(5) Magnesium oxide scrubbing

(6) Catalytic oxidation.

All of the above processes except catalytic oxidation use a wet scrubber. Catalytic oxidation is a high-temperature process and is, therefore, at a disadvantage for retrofit situations.

Table 1 shows the full-scale demonstration plants that have operated or will soon operate on boilers in the United States to remove SO_2. The EPA has given financial assistance to the demonstration programs at Key West, Northern Indiana Public Service, Boston Edison, and Illinois Power. So far, only 44 desulfurization units have been installed or are planned in utility plants producing a total of 18,000 MW. At least 300 installations are needed to meet primary ambient-air standards, so it is clear that the utility industry cannot meet the mid-1975 deadline. Therefore, the EPA has been granting extensions of up to two years in some cases.

The cost of installing and operating an SO_2 removal system depends on the process, the size of the unit, and the amount of sulfur in the fuel. Location and waste disposal may also have a large effect on costs. It has been estimated that the capital cost of these systems range from $35 to $65 per kilowatt while the operating costs range from 1 to about 3 mills per kilowatt-hour.(3) A better estimate for present conditions would probably put the range of capital costs between $40 to $75 per kilowatt and the operating costs closer to 3 mills per kilowatt-hour. Problems with waste disposal or location could increase these costs. Capital costs for lime scrubbing systems, which will probably be used for Colstrip Units 3 and 4, range from about $40 to $60 per kilowatt which does not include the disposal pond.

TABLE 1. FULL-SCALE DEMONSTRATION PROGRAMS ON BOILERS IN THE UNITED STATES

	Limestone Injection		
1968	Union Electric - Meramec	Comb. Engr.	140-MW Coal
1968	Kansas P&L -Lawrence	Comb. Engr.	125-MW Coal
1971	Kansas P&L - Lawrence	Comb. Engr.	400-MW Coal
1972	Kansas City P&L - Hawthorn	Comb. Engr.	130-MW Coal
1972	Kansas City P&L - Hawthorn	Comb. Engr.	130-MW Coal
	Limestone Scrubbing		
1972	Commonwealth Edison - Will County	B&W	156-MW Coal
1973	City of Key West - Stock Island	Zurn	37-MW Oil
1973	Kansas City P&L - La Cygne	B&W	820-MW Coal
1973	Arizona Public Service - Cholla	Research-Cottrell	115-MW Coal
1973	Detroit Edison - St. Clair	Peabody	180-MW Coal
1974	Southern California Edison - Mohave	UOP	160-MW Coal(a)
1975	TVA - Widow's Creek	TVA	550-MW Coal
1976	Northern States Power - Sherburne County	Comb. Engr.	680-MW Coal
1977	Northern States Power - Sherburne County	Comb. Engr.	680-MW Coal
	Lime Scrubbing		
1973	Louisville G&E - Paddy's Run	Comb. Engr.	65-MW Coal
1973	Duquesne Light - Phillips	Chemico	180-MW Coal
1973	Southern California Edison - Mohave	Stearns-Roger	160-MW Coal(a)
1974	Ohio Edison - Bruce Mansfield	Chemico	880-MW Coal
1975	Ohio Edison - Bruce Mansfield	Chemico	880-MW Coal
1976	Columbus and Southern Ohio - Conesville	Not selected	2 x 375-MW Coal
	Alkali Scrubbing without Regeneration		
1972	General Motors - St. Louis, Mo.	C.E.A.	15 and 8-MW Coal(b)
1973	Nevada Power - Reid Gardner	C.E.A.	125-MW Coal
1973	Nevada Power - Reid Gardner	C.E.A.	125-MW Coal
1975	Nevada Power - Reid Gardner	C.E.A.	125-MW Coal
	Alkali Scrubbing with Calcium Regeneration		
1974	General Motors - Parma, Ohio	GM	25-MW Coal(b)
1974	Caterpillar Tractor - Joliet, Ill.	Zurn	10 and 8-MW Coal(b)
1975	Caterpillar Tractor - Mossville, Ill.	FMC	15,8, and 8-MW Coal(b)

TABLE 1. (Continued)

	Alkali Scrubbing with Thermal Regeneration		
1975	Northern Indiana Public Service - D. H. Mitchell	Davy Power Gas	110-MW Coal
	Magnesium Oxide Scrubbing		
1972	Boston Edison - Mystic	Chemico	150-MW Oil
1973	Potomac Electric - Dickerson	Chemico	95-MW Coal
1973	Philadelphia Electric - Eddystone	United Engineers	120-MW Coal
	Catalytic Oxidation		
1972	Illinois Power - Wood River	Monsanto	110-MW Coal

(a) 20 percent of gas flow from 790 MW unit.

(b) Industrial boiler with equivalent MW rating.

B. Reliability and Efficiency

Status of Lime/Limestone Processes

There are about 14 full-scale demonstration projects for limestone or lime scrubbing on utility boiler stack gas that have been started up in the United States since 1968, but so far they have met with only limited success. Limestone/lime scrubbing can be operated three ways, either by injecting limestone into the power plant boiler and catching it in a wet scrubber after the air preheater, or by introducing limestone or lime directly into the scrubber system. Limestone injection into the boiler has fallen into disfavor because of operating problems such as abnormal slagging and increased erosion in the boiler and plugging in the scrubber. Plans call for the four limestone injection demonstration plants still operating to be converted to tail-end limestone scrubbing.

By reference to Table 1 it can be seen that limestone injection was pioneered by Combustion Engineering and was first practiced commercially at the Meramec Plant of Union Electric in 1968. Combustion Engineering favors the use of marble bed absorbers. Because of special construction features of the Union Electric boilers, the plant was especially susceptible to fouling of the boiler tubes and the experiment was eventually terminated. There were also additional problems with scrubber scaling, demister operation, and waste disposal. In late 1968, the limestone injection system on a 125-MW unit at Lawrence was started up by Kansas Power and Light Company in a simple configuration with no slurry recycle to the scrubber. This system encountered problems with gas distribution, scrubber plugging, corrosion, and erosion. After several years of operation (mostly during the winter when coal is being fired) and many modifications, the unit is still experiencing problems. A new 400-MW unit was started up at Lawrence with limestone injection in late 1971 with a design based on the experience with the 125-MW unit. However, both units are still experiencing scaling problems in the scrubber, which has made it necessary to reduce the limestone feed to the

boiler at the expense of lower SO_2 removal efficiencies. The units are kept in operation by nightly cleanup of half of the scrubbers which are taken off line when the system is at reduced load. Kansas Power and Light is going to switch both units to tail-end limestone scrubbing. Two additional limestone injection systems went on stream in late 1972 at Kansas City Power and Light's Hawthorn Station and they have been experiencing similar problems to those at Lawrence. The point of limestone injection has been switched from the boiler to the air preheater exit so that limestone rather than lime is now carried into the scrubber by the flue gas.

Will County Unit 1 of Commonwealth Edison was retrofitted with tail-end limestone scrubbing to circumvent the troubles from boiler injection and the scrubbers were started up in February, 1972. The scrubbing system was purchased from Babcock and Wilcox and involves Venturi scrubbers in series with either a sieve plate column or a turbulent contact absorber (two parallel scrubbing modules). The major nonmechanical problems involve plugging of the demisters above the scrubbers and corrosion of the reheater tubes. Waste disposal of the sludge, which has some of the characteristics of quicksand, is an unsolved problem; however, the sludge can be stabilized by the addition of lime and fly ash. During two years of operation, the availability of one of the scrubbing modules has been about 25 percent.

The Key West oil-fired plant built by Zurn Industries uses a sea water slurry of native coral and was scheduled to go on stream in July 1972, but was delayed by operational problems until August 1973. The system uses a Zurn absorber design which requires a stoichiometric ratio of 3.5 to achieve an SO_2 removal efficiency of about 70 percent. Thus far, the system has minimal operating experience because of problems with controlling the liquid level in the scrubber, which is very critical for proper operation. Sludge disposal on the space-limited island is a very major unsolved problem.

The La Cygne plant of Kansas City Power and Light employs a seven-module Babcock and Wilcox system, similar to that of Will County, each of which can operate independently of the other. This station is

experiencing problems with both the generating plant and the scrubbers. First reports from Arizona Public Service's Cholla plant where Research-Cottrell has installed a tail-end limestone scrubbing system indicate that the system is working well. However, several more months of operating experience will have to be achieved before any definite conclusions can be reached.

Perhaps the most successful demonstration plant in the United States to date is the carbide lime scrubbing installation at Louisville Gas and Electric's Paddy's Run Station.(4) The system was purchased from Combustion Engineering and uses marble bed absorbers. From start-up in April 1973 through December 1973, the system had an availability of 90 percent with the longest continuous run being 45 days. However, in order for the system to be widely applicable to other utilities, the successful use of hydrated lime rather than carbide sludge should be demonstrated. Also, the system at Paddy's Run has avoided the formidable problems of stack gas reheat and waste disposal by using natural gas for reheat and by dumping the sludge in a borrow pit. The first demonstration plant using hydrated lime in the United States is the Chemico installation at Duquesne Light's Phillips Station. However, the system which started up in April 1973 was shut down the following October because of leakage in the stack, corrosion cracking near the welds in the induced draft fans, and abrasion and corrosion in the scrubber vessel. The system was started up with fly-ash removal only, and the reactant lime has not yet been tried. The experience to date with limestone/lime scrubbing systems for SO_2 control indicates that slow progress is being made with tail-end systems.

Status of Alkali Processes

Alkali scrubbing for SO_2 can be operated in several modes, three of which--no regeneration, calcium regeneration, and thermal regeneration--are in operation or soon will operate on boilers in the United States. The General Motors Assembly Plant in St. Louis is currently using an open-loop NaOH scrubbing system designed by Combustion Equipment Associates to remove SO_2 from the stack gas of a steam-generating system which is

equivalent to about 25 MW. Since startup in 1972, the system availability has been greater than 90 percent. The scrubber effluent is being oxidized to Na_2SO_4 solution and discharged into the city sewer system. Water authorities have allowed this effluent to be discharged when combined with the other waste streams from the plant. At other plant locations, General Motors is planning to use calcium regeneration of the spent alkali stream (double alkali process).

Sodium scrubbing without regeneration is also being used on two 125-MW units at Nevada Power Company's Reid Gardner plant. The system utilizes a crude natural brine evaporate containing 50 weight percent Na_2CO_3, 15-20 weight percent Na_2SO_4, and 5 weight percent Na_2B_4O. The waste stream consisting mainly of Na_2SO_3 and Na_2SO_4 is discharged to open ponds located at the plant site in the desert for natural evaporation of the water. Since the station burns low-sulfur coal, the emission of sodium wastes is lower than usual. While this process is possibly a suitable expedient in climates where rainfall is small, it is relatively expensive and without alternative waste disposal schemes it is probably not suitable for many areas of the United States.

One way to avoid the sodium salt waste disposal problem is to react the scrubber effluent with limestone and/or lime to precipitate calcium sulfite and sulfate and yield a solution of NaOH and Na_2SO_3 for recirculation back to the scrubber. This process is known as the double alkali system. The precipitated solids are sent to a vacuum filter for separation. Except for sodium salts adhering to the filter cake, the waste disposal problem becomes one of calcium sludge disposal. The sodium losses, which are made up by using either Na_2CO_3 or NaOH, can be minimized by thorough washing of the calcium filter cake. One of the main problems associated with the double alkali process is the difficulty in regenerating Na_2SO_4 because it does not react well with hydrated lime. The installation at the General Motors plant in Parma, Ohio, on an industrial boiler equivalent to about 25 MW was started up about one month ago and is currently experiencing many operating problems. Two other installations on industrial boilers are scheduled to start up this year so that definitive operating data probably will not be available before 1975.

An obvious way of eliminating the problem of disposing of soluble sodium salts is to operate an SO_2 recovery process where the sodium salts are recycled. In the Wellman-Lord process, the SO_2 is recovered by thermal stripping. The process is licensed by Davy Powergas Company of Lakeland, Florida. The process has been in operation on two oil-fired industrial boilers, each equivalent to about 35 MW, at Chiba, Japan, since August 1971. The concentrated SO_2 is used to produce sulfuric acid. One of the major problems with the process is the requirement for a bleed stream to remove Na_2SO_4. About 10 percent of the total incoming sulfur at Chiba is lost as soluble Na_2SO_4. Two other Wellman-Lord installations for treating stack gas from oil-fired boilers have started up in Japan during 1973. One is a 220-MW equivalent industrial boiler at Chiba. Thus far, the only Wellman-Lord installations in operation in the United States are for treating tail gas at Claus plants and sulfuric acid plants. The first boiler installation in the United States is the EPA-supported demonstration at the coal-fired Mitchell station of Northern Indiana Public Service Company in Gary. This unit will produce elemental sulfur which is the most desirable product from an environmental viewpoint if marketing of sulfuric acid is not feasible. The unit will not get into operation until 1975 so that it will be awhile before useful information for coal-fired boilers is obtained. A problem anticipated in adapting the Wellman-Lord process to coal-fired plants is the necessity for removing particulate matter prior to the absorber. Even if good particulate removal is obtained, the absorption liquor may have to be filtered.

Status of the Magnesium Oxide Process

The MgO scrubber at Boston Edison's Mystic Station went on stream in April, 1972, using a process designed by Chemico. The product, magnesium sulfite and sulfate, is shipped to a chemical company in Rumford, Rhode Island, for regeneration of the magnesia and production of by-product H_2SO_4. The plant generally operates on 2 percent sulfur fuel oil, although low-sulfur oil is used when the scrubber circuit is not functioning properly. The prototype scrubber was scaled up by a factor of 300 from a 1,500-cfm pilot scrubber in which all the solids handling operations were

not coupled together. The problem areas have included dryer dust emission, centrifuge vibration and wear, pump and piping erosion, and miscellaneous minor equipment failures. The dryer dust problem was solved by rerouting the dryer off gas to the scrubber inlet rather than the stack, but this means that there is no stack-gas reheat. The MgO has been recycled between four and eight times with no significant loss of reactivity; however, the makeup requirements have not yet been pinned down. The scrubber availability has been about 30 percent during almost two years of operation with the longest continuous run being four and one-half days.

The installation at Mystic Station has not provided information on the effects of fly ash on system operability since the boiler is oil fired. Fly ash must be efficiently removed ahead of the MgO scrubber to prevent its buildup in the recycled material. Two MgO scrubbing installations on coal-fired boilers have started up during 1973 at Potomac Electric's Dickerson Station and Philadelphia Electric's Eddystone Station. Early reports from Dickerson Station indicate that the process is working well but a significant amount of operating time has not been accumulated yet.

Status of the Catalytic Oxidation Process

One of the early processes, based on early work at Bituminous Coal Research (USA) and British Coal Utilization Research Association, involves catalytic oxidation of the SO_2 to SO_3, the SO_3 then being dissolved in sulfuric acid to produce additional sulfuric acid. A group composed of Monsanto, Pennsylvania Electric, Research-Cottrell, and Air Preheater began major work in the early 1960's to develop a suitable catalyst system. A pilot plant capable of treating the flue gas equivalent of 15 MW of generation was operated at the Portland Station of Metropolitan Edison, but is now dismantled. The Illinois Power Company installation by Monsanto was started up in September 1972 but was only operated for a few days to try out the natural gas and fuel-oil fired reheat burners. Because of the shortage of natural gas, it was decided to go exclusively with fuel-oil reheat. The system was shut down after it became apparent that the catalyst and the Brink's demisters had to be protected against fouling while the reheat

burners were being adjusted. After extensive modification, the system did operate with No. 2 fuel oil in July 1973, but it was obvious that the continuous operation of the in-line heaters would cause excessive contamination of the catalyst. It was decided to construct an external reheat burner with the required heat being ducted into the system at the location of the in-line burners. The installation is expected to start up again in April 1974, but it appears that the more than two million gallons per year of No. 2 fuel oil required for the system will not be available. An important operating question which is not yet resolved is the effect of flyash contamination on the life of the catalyst. Also, because of the reheat problems, the catalytic oxidation process is probably not suitable for retrofit installations.

C. Stack Gas Reheat

One of the major problems to be dealt with in many SO_2 control processes is the cooling of the flue gas from about 300 F (air preheater exit temperature) to its saturation temperature of about 125 F. Much emphasis has been placed recently on the use of high stacks to improve dispersion and reduce the possibility of localized high-pollutant concentrations. A reduction in stack gas temperature by wet scrubbing will reduce both the momentum and buoyancy which cause the plume to rise above the stack after it is emitted. Thus, the effective stack height and the plume dispersion will be reduced by wet scrubbing. This would not be serious if essentially all of the objectionable components were removed in the scrubber, but such efficiency is not likely. Humidification of the stack gas is also objectionable because serious corrosion problems can occur with the stack lining unless it is acid resistant also. Condensation may occur and cause formation of a visible plume which could have an undesirable psychological impact on the public and which could have adverse effects on plume dispersion.

Plume Dispersion. TVA has carried out comprehensive studies of plume dispersion from coal-fired, electric generating plants. Based on this experience the effect of stack gas temperature on maximum SO_2 concentration at ground level was determined for a 300-foot-high stack. Reduction in ground-level concentrations for various scrubber efficiencies at different degrees of reheat is shown in Figure 2. This figure includes low removal efficiencies and thus shows the effect of gas cooling on ground concentration of gas constituents such as nitrogen oxides that are removed to only a limited degree in the scrubbing process. If 30 percent removal of nitrogen oxides is assumed, the gas would have to be reheated to 190 F to avoid an increase in ground-level concentration as compared with normal power-plant operation. Figure 2 also shows that for a desired SO_2 scrubber efficiency of 85 percent, a stack gas reheat temperature of 150 F will result in a 75 percent reduction in ground-level SO_2 concentration. Therefore, the stack gas should be reheated to at least 150 F to minimize the ground-level concentration of SO_2 and to avoid the presence of mist in the

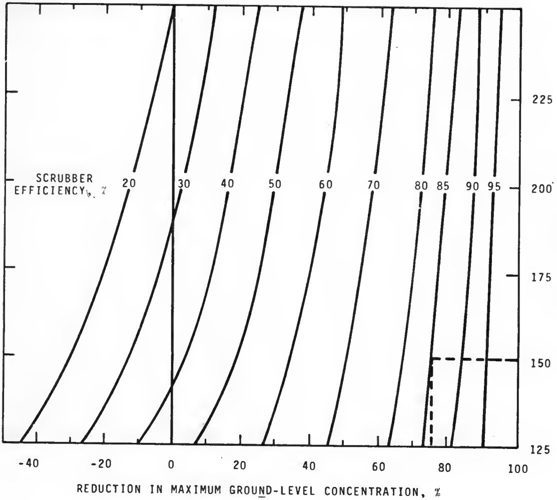

FIGURE 2. Effect of Reheat Temperature on Ground-Level SO_2 Concentration at Various Scrubber Efficiencies for 300-Foot Stack (Base: Maximum Ground-Level Concentration at 310°F Stack Temperature and Without Scrubber)

(Source: Anon., "Sulfur Oxide Removal from Power Plant Stack Gas--Use of Limestone in Wet Scrubbing Process," Conceptual Design and Cost Study No. 2, Contract No. TV-29233A, 1969.)

gas as it leaves the stack. However, it may be necessary to reheat the gas to higher temperatures if the ground-level concentration of nitrogen oxides or the appearance of the plume present problems. For these reasons, it is desirable that the method chosen for stack gas reheat should provide for varying the reheat temperature between 150 F and 250 F depending upon weather conditions and air pollution regulations. It is believed that reheating beyond 250 F would not be attempted because of the relatively high cost for going to higher levels.

Reheat Methods. There are three general classes of reheat methods; they are (1) obtain energy from coal burned in main boiler, (2) economize on heat content of flue gas, and (3) add supplemental source of heat. Each of these classes can be subdivided into several different methods as follows:

(1) Obtain energy from coal burned in main boiler
    (a) Hot water-to-gas heat exchanger
        1. Direct
        2. Indirect
    (b) Steam-to-gas heat exchanger
        1. Direct
        2. Indirect
    (c) Hot air (preheater)-to-gas heat exchanger
    (d) Hot air from preheater mixed with stack gas
(2) Economize on heat content of flue gas
    (a) Gas-to-gas heat exchanger
        1. Shell and tube type
        2. Regenerative type (Ljungstrom)
    (b) Gas-to-liquid-to-gas heat exchangers
    (c) Bypass part of the flue gas around scrubber
(3) Add supplemental source of heat
    (a) Direct combustion
        1. Coal
        2. Fuel oil
        3. Natural gas

(b) Indirect combustion
   1. Coal
   2. Fuel oil
   3. Natural gas.

Several of the methods on the above list can be ruled out as infeasible or undesirable, especially for a retrofit situation. For example, Methods 1c and 1d would require replacement of the existing air preheater and would upset the thermal balance of the plant. Method 2c would result in a higher than necessary ground-level concentration of SO_2. If scrubber bypass (Method 2c) of 25 percent of the flue gas (at 300 F, the air preheater outlet temperature) and 85 percent removal of the SO_2 from the remainder are assumed, the resulting stack gas temperature would be about 169 F and the net degree of SO_2 removal 63.8 percent. As seen from Figure 2, the resulting reduction in ground-level concentration would be only about 43 percent. In contrast, scrubbing all the gas but with no reheat would give a ground-level concentration reduction of 72 percent; therefore, Method 2c can be ruled out.

Method 3 using fuel oil or natural gas is undesirable because of the need for an auxiliary fuel which is currently in short supply. The use of coal in Method 3 is limited by the amount of particulate matter that would be added to the stack gas by a stoker-type of reheater. Particulate emission regulations are becoming very stringent so that a coal-fired reheater may be infeasible. Furthermore, Method 3b is considered infeasible because it would require large quantities of expensive materials of construction to contain very hot flue gas on one side of a heat exchange and allow large volumes of stack gas to flow through the other side of the exchanger.

Of the remaining methods, Methods 2a and 2b are more desirable than Methods 1a and 1b because they make use of heat that otherwise would be wasted and do not cause a derating of the power plant. However, Method 2b requires two shell and tube heat exchangers, while Method 2a requires one large shell and tube heat exchanger or a regenerative type heat exchanger. The cost of the shell and tube heat exchanges and the fact that they would cause a rather large increase in flue gas pressure drop could mean a significant increase in system operating costs. A regenerative type heat

exchanger would be highly desirable but would have to withstand the corrosive conditions.

Methods 1a and 1b using direct contact of the heat exchanger surface with the flue gas are currently being attempted at full-scale SO_2 scrubbing installations. However, severe corrosion problems are being experienced with Method 1b. One way of avoiding the corrosion problem is to use the steam coils to heat air which is injected into the stack gas; however, this method would increase the load on the induced draft fans.

Corrosion Problems. At Commonwealth Edison's Will County Station, a tail-end limestone scrubbing system is being used for SO_2 control. The reheat system consists of 350 psig steam with 50 F of superheat in coils which directly contact the gas. The coils are smooth tubes with a rectangular pitch and consist of three sections of nine tube bundles each. Originally, the first section was SS304 and the other two sections were corten steel and the stack gas was supposed to be reheated from 120 F to 200 F; however, reheat to 175 F is now considered adequate. Initially, there was a vibration problem with the tube bundles that was corrected by putting in baffles. Deposition of scrubber slurry carryover through the demister causes corrosion of the reheater tubes; chloride corrosion attacks the SS304 and acid corrosion attacks the corten steel. The reheater tubes are going to be replaced with six bundles of Inconel 625 tubes, three bundles of Incoloy 825 tubes, and 12-15 bundles of carbon steel tubes. The costs of the tube bundles are as follows:

Inconel 625	\$8500
Incoloy 825	\$6000
SS304	\$2500
Corten steel	\$1200

The same type of reheat system as the original Will County system has also been tried at Kansas City Power and Light Company's La Cygne Plant which also utilizes tail-end limestone scrubbing. This plant has also been plagued by corrosion of the reheater tubes.

At the Lawrence Plant of Kansas Power & Light Company, limestone injection into the boiler followed by wet scrubbing of the flue gas exiting

the air preheater is used for SO_2 control. The reheat system consists of hot water from the feedwater deaerator at about 270 F in mild steel tubes with carbon steel fins in direct contact with the flue gas. The fins are 60 mil thick and are spaced 2 or 3 per inch. The stack gas is reheated from about 125 F to about 150 F and it is significant to note that reheater tube corrosion does not appear to be a problem. A similar system is employed at the Hawthorn Station of Kansas City Power & Light also without any major reheater tube corrosion problems.

D. Sludge Disposal

One of the major problems inherent in flue gas desulfurization systems based on lime or limestone is the necessity to dispose of or utilize large quantities of sludge. At present, lime/limestone scrubbing systems generate a sludge with little commercial value. Lime scrubbing processes ordinarily produce sludges containing $CaSO_3 \cdot 1/2\ H_2O$, $Ca(OH)_2$, $CaSO_4 \cdot 2H_2O$ and $CaCO_3$; while limestone sludges generally contain $CaSO_3 \cdot 1/2\ H_2O$, $CaSO_4 \cdot 2H_2O$, and $CaCO_3$. For coal-fired installations where efficient particulate removal is not installed upstream of the absorber, such sludges can contain large quantities of fly ash.

The amount of sludge generated by a given plant is a function of the sulfur and ash content of the coal, the coal usage, the on-stream hours per year (load factor), the mole ratio of lime or limestone added to the amount of SO_2 removed, the SO_2 removal efficiency, the ratio of sulfite to sulfate in the sludge, and the percent moisture in the sludge. Table 2 lists values of these various sludge parameters for a hypothetical plant representing the national average expected between 1973 and 1980.

The SO_2 removal efficiency will vary from one flue gas desulfurization system to the next as a function of local requirements. Typically, an SO_2 removal efficiency of about 85 percent is required to meet the standards for plants burning eastern coal.

Since unreacted additive is disposed of with the sludge, the stoichiometry of lime or limestone addition (the CaO/SO_2 or $CaCO_3/SO_2$ mole ratios) greatly influences the amount of sludge to be handled. The CaO/SO_2 and $CaCO_3/SO_2$ mole ratios vary from system to system at present but the general trend is toward lower values as operating experience is gained. Reasonable values for this ratio are 1.0 and 1.2, respectively.

Other factors influencing the amount of sludge to be handled are the load factor of the plant, the coal use rate, and the mole ratio of sulfite to sulfate in the sludge. The amount of sludge produced by a plant is directly proportional to the number of hours per year that the plant operates and the coal usage of the plant. The 6400 hr/year and 0.88 lb coal/kWh values used for those calculations are typical of large

TABLE 2. TYPICAL SLUDGE PRODUCTION PARAMETERS

Sludge Production Parameters	National Average
Coal:	
Sulfur Content	3.0%
Ash Content	12%
Plant:	
Load Factor	73%
Coal Usage	0.88 lb/kWh
Scrubbing Systems:	
SO_2 Removal Efficiency	85%
Moisture in Sludge	50%
CaO/SO_2 (inlet) Mole Ratio	1.0
$CaCO_3/SO_2$ (inlet) Mole Ratio	1.2
Sulfite/Sulfate Mole Ratio	9:1

modern generating stations. Obviously, if the plant is on line a larger fraction of the year or more coal is required per kWh, the amount of sludge produced will increase. The sulfite to sulfate ratio in the sludge effects the weight of the sludge produced as $CaSO_4 \cdot 2H_2O$ is heavier than $CaSO_3 \cdot 1/2\ H_2O$. The ratio assumed in this discussion is 9:1.

Ponding and landfilling currently provides the major mechanism for disposal of lime/limestone sludges from flue gas desulfurization systems. As such, there are three problems associated with this practice. First, the land use for waste disposal is aesthetically objectionable. Second, the sludge could provide varying degrees of surface and groundwater pollution depending upon chemical composition, solubilities, and the location, design, and operation of the disposal site. The potential water pollution problems derived from the chemical composition of the sludge may be classified as

(1) Soluble toxic species (toxic meaning elements which can cause health problems even at low concentrations)
(2) Chemical oxygen demand
(3) Excessive total dissolved solids
(4) Excessive levels of specific species, e.g., sulfate and chloride, not generally thought of as a toxic
(5) Excessive suspended solids (some of which might dissolve later).

Thirdly, for land reclamation, most of the stable wastes will require only a cover material to support vegetation and prevent eventual erosion. However, some wastes are very resistant to dewatering and could reslurry in the pond or landfill. If this is shown to be true, it is likely that chemical fixation will become a necessary practice. Chemical fixation of limestone scrubber sludge is currently being practiced at the Will County Station of Commonwealth Edison.

The alternative to disposal of scrubber sludges is development of commercially applicable utilization processes. Numerous programs in this area have been conducted through Government sponsorship and by industry. These may be summarized as

Sludge Utilization Schemes

- I. Filler Material
    - A. Structural Fill
    - B. Mine Void Fill
    - C. Filler in Bituminous Concrete
    - D. Waste Disposal/Sanitary Structural Landfill
- II. Pozzolanic Products
    - A. Road Base Course
- III. Autoclave Products
    - A. Concrete Admixture (Structure and Products)
    - B. Fired Brick
    - C. Lightweight Aggregate
- IV. Pressure Sintered Products
    - A. Metal Coatings
    - B. Pipes
- V. Gypsum Products
    - A. Plaster
    - B. Wallboard
- VI. Soil Amendment
- VII. Mineral Wool
- VIII. Mineral Recovery
    - A. Lime
    - B. Aluminum
    - C. Iron
    - D. Pozzolan (glass particles)
    - E. Titanium
    - F. Silicon
    - G. Rare Elements
- IX. Sulfur Extraction
    - A. Sulfur
    - B. Sulfuric Acid
- X. Polluted Water Treatment
    - A. Recovery of polluted streams, ponds, lakes
    - B. Neutralization of Acid Mine Drainage and Polluted Waters
    - C. Sewage Plant Treatment

Although many of the above schemes have been proposed as uses for lime/limestone scrubber sludges, none is being currently utilized by the U.S. power industry.

E. Coal Properties Related to SO_2 Removal

The coal to be used in Units 3 and 4 will be supplied by Western Energy Corporation, a wholly owned subsidiary of Montana Power Company. The coal is strip-mined from two seams which differ in sulfur contents. The principal seam is the Rosebud, which lies under 25 to 175 feet of overburden and is about 25 feet in thickness. About 10 to 25 feet below the Rosebud seam is the McKay seam, which is about 8 to 9 feet thick. The fuel for Units 3 and 4 will be primarily from the Rosebud seam and will contain from 0 to 40 percent coal from the McKay seam.

The SO_2 removal properties of 9 samples of the coal are shown in Table 3. Three of these samples are from the Rosebud seam, while the remaining six are from the McKay. These samples indicate that the McKay seam has slightly higher heating values and sulfur contents but slightly lower ash contents. The sulfur content within the McKay seam is very heterogeneous as shown by the range within a given sample. The entire range may occur over a one-foot depth interval. The sulfur contents and heating values of both seams are such that sulfur removal is required to meet both the Montana standard (1 lb S per million Btu) and the Federal standard (1.2 lb SO_2 per million Btu).

The ash in these coals has a relatively high calcium and magnesium composition and much of this is in an alkaline form. This alkalinity is used in the scrubber system to remove much of the sulfur in the flue gas. Table 3 gives the percent sulfur that could potentially be removed if all the calcium and magnesium in the ash were in an alkaline form and all of this could react stochiometrically with the sulfur. The values in Table 3 indicate that almost all the sulfur could be removed with Rosebud coal, but only about half could be removed with McKay. In reality, only part of the calcium and magnesium is in an alkaline form and the reaction within a scrubber is only about 50 percent complete. Also, part of the ash appears as bottom ash in the boiler and is not carried over to the scrubber with the flue gas. In spite of these limitations, pilot-plant tests indicated 40 to 60 percent SO_2 removal in the scrubber with just the alkalinity from the fly ash.

TABLE 3. PROPERTIES OF COAL SAMPLES RELATED TO SO_2 REMOVAL

Sample Identification			Heating Value, Btu/lb	Sulfur Composition, percent		Lb Sulfur Per Million Btu		Ash Content, percent	S Removed by Ash, percent(c)
Seam(a)	Location	Depth, ft		Total Sample	Range	As S	As SO_2(b)		
R	N39E21	82.0-104.5	8112	1.02	--	1.27	2.51	13.3	89.2
R	N39E20	62.0-84.0	8025	1.03	--	1.28	2.56	11.2	96.7
R	N36E22	128.0-150.0	8406	1.31	--	1.56	3.11	14.1	108.9
	Average Rosebud		8181	1.12		1.37	2.73	12.9	98.3
M	N39E21	194.0-202.7	8199	1.40	0.35-5.45	1.72	3.44	10.5	70.7
M	N39E20	170.0-177.5	8378	1.16	0.34-4.47	1.39	2.76	6.9	52.5
M	N36E22	254.0-260.0	8426	2.19	0.44-5.21	2.60	5.19	7.7	31.6
M	N39E18	195.0-200.7	8940	1.03	0.41-4.25	1.15	2.30	6.3	87.0
M	N39E19	162.0-169.3	8104	1.78	0.63-5.35	2.20	4.38	10.7	42.1
M	N48E28	119.2-124.2	8389	1.91	0.53-6.62	2.28	4.54	7.2	37.8
	Average McKay		8406	1.58		1.89	3.77	8.2	53.6

(a) R refers to Rosebud seam, M to McKay

(b) Assumes all sulfur converted to SO_2.

(c) Potential percent of sulfur in coal removed by ash if all Ca and Mg were available for removal.

F. SO_2 Removal System For Colstrip Station

The SO_2 removal system selected by Montana Power Company for Colstrip Units 1 and 2 will probably also be used for Units 3 and 4. This system consists of wet scrubbing utilizing the alkali content of the fly ash for partial SO_2 removal. This installation will have the capability of removing a higher percentage of SO_2 by the use of lime addition as a back-up system. The pollution control system consists of three venturi scrubber trains to handle flue gas from each of 360-MW generating units. Each train consists of a venturi scrubber, reheater, induced draft fan, and associated ductwork and piping. The bleed from the three scrubber trains is combined and pumped to an ash pond. Each scrubber, which is 35 feet in diameter, provides two contacts between liquor and gas streams for optimum removal of both fly ash and SO_2. The first contact, which is in the venturi throat section, is of co-current flow type. The second contact is counter-current flow type and occurs in the separator section where the flue gas is exposed to sprayed liquor after passing through the venturi throat and before entering the mist eliminator. Essentially all the flyash removal is attained in the throat section with partial removal of SO_2, and the counter-current spray sections are used to optimize SO_2 removal. Using fly ash alone, the system is supposed to remove about 40 to 60 percent of the SO_2. The addition of lime, of course, will increase the SO_2 removal capability of the system.

The problems encountered with wet scrubbing systems of this type include erosion of pumps and valves, scaling in the recycle loop, plugging of the mist eliminator, corrosion of reheater tubes, and sludge disposal. Erosion problems can be minimized by using rubber-lined pumps and piping, as will be done at Colstrip, and by using valves only in the fully open or fully closed modes and not as flow modulators. Scaling in the recycle loop is minimized by providing a high solids concentration in the slurry and a high liquid-to-gas ratio in the scrubber. Plugging of the chevron-type mist eliminators can be prevented by a spray washing system located below the mist eliminator and by using makeup water rather than recycle water for the wash. In some installations, the use

of a two-stage mist eliminator has proved beneficial. At Colstrip, the single stage mist eliminator will be washed from above and below with fresh makeup water.

Corrosion of reheater tubes can be prevented either by using a corrosion resistant alloy for the steam coils or by keeping the coils out of direct contact with the flue gas. In the latter method, the coils are used to heat ambient air which is then injected into the flue gas to provide reheat. This method of reheat puts a bigger load on the dry, induced-draft fans which are located after the reheaters. The plan at Colstrip is to use Inconel alloy steam coils directly in contact with the flue gas to provide a maximum of 50 F of reheat. Inconel alloy is very expensive, but it should be able to withstand the corrosive conditions including stress corrosion cracking induced by the presence of chlorides. In addition, soot blowers will be included to clean out any possible buildup on the heat exchanger surfaces.

The calcium sulfite/sulfate sludge will have to be ponded at Colstrip. For 50 percent SO_2 removal on Units 1 and 2, the amount of sludge produced (assuming 50 percent solids) will be about 26 tons/hr in addition to the fly ash collected. These ponds can cause potential problems if any leaching into the groundwater occurs. Any pond evaporation helps alleviate plugging problems in the scrubber system by allowing more makeup water to be used.

A similar type system, in terms of mechanical equipment, to the one to be installed at Colstrip has been in operation at Reid Gardner Station in Nevada since March 1974. However, the SO_2 removal is accomplished by adding alkali in the form of soda ash or trona. Since the chemistry is based on sodium salts rather than calcium salts, many of the problems associated with plugging and scaling are eliminated. The use of soluble sodium salts is probably limited to very arid regions such as in Moapa, Nevada. The scrubber is meeting design criteria for both particulate and SO_2 removal. It is very difficult to extrapolate the results of SO_2 removal in a sodium system to that in a calcium system because the large difference in solubility means that the liquid-phase resistance to mass transfer is different.

Public Service of Colorado has been using a three-stage turbulent contact absorber to remove fly ash from flue gas at Valmont and Cherokee Stations. They found that the type of coal has a tremendous effect on incidental SO_2 removal in the scrubbers. High calcium ash takes out up to 54 percent of the SO_2 at Valmont, but with a different ash only 13 percent of the SO_2 is removed at Cherokee, although the scrubbers are very nearly identical.

The scrubber system design for Colstrip Units 1 and 2 was based on work performed at a 3,000-ACFM pilot-plant installation at Montana Power Company's Billings Station. The pilot plant was used to establish the design criteria for particulate and SO_2 removal efficiencies for the full-scale Colstrip Station Units. It was successfully operated and demonstrated that the proposed full-scale equipment should operate better than design criteria on particulate removal and that there should be sufficient alkali in the fly ash entering the scrubber to reduce the SO_2 from 965 ppm to 425 ppm without alkali addition. However, additional alkali will be added, in the form of lime, to control pH in the scrubber.

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III. STATE-OF-ART OF FLYASH REMOVAL

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III. STATE-OF-ART OF FLYASH REMOVAL

A. Introduction

Proposed power plants Colstrip 3 and 4 will depend on state-of-art methods for removal of potential airborne polutants after combustion. The airborne solid particulate fraction (flyash) from pulverized coal units is usually 80% of the total coal ash (20% is bottom ash). It typically consists of solid spherical ceramic particles with a mass mean diameter of 5-10 micron. Conventional means of removing flyash usually are employed after the useful heat is extracted from the conbustion gases with one exception; i.e., hot electrostatic precipitators operate upstream of the air preheater. To meet federal, state and local particulate emission controls (federal are 0.1 lb ash/10^6 Btu and a 20% opacity maximum plume), coal-fired plants today can choose between the following options:

- Low temperature electrostatic precipitators
- High temperature electrostatic precipitators
- Wet scrubbers (venturi type)
- Baghouse filter systems

It is the purpose of this section to discuss each of the above in terms of its applicability to Colstrip Units 3 and 4 burning low sulfur ($\leq$ 1%) Rosebud and McKay coal. The efficiency, operational dependability, physical characteristics, and some cost information are discussed. No recommendation as to a best choice is given.

B. Cleanup Requirements of Airborne Flyash in the Power Plant

For typical operating condition of Colstrips 3 or 4, the flue gas entering the flyash cleanup system downstream from the air preheater will have the approximate properties as shown in Table 1.

TABLE 1. Precleanup Conditions of Colstrip 3 and 4 Flue Gas

Temperature	300°F	
Flow rate	3.2×10^6 acfm (per unit)	
Fuel	100% Rosebud (Table 3, SO_2 Section)	60% Rosebud, 40% McKay
Flyash Load	2.74 gr/acf	2.31 gr/acf
	4.23 gr/scfd*	3.57* gr/acf
Flyash load based on fuel energy	$12.6 \frac{\text{lb ash}}{10^6 \text{ Btu}}$	$10.66 \frac{\text{lb ash}}{10^6 \text{ Btu}}$
Federal Emission Standard	$0.1 \frac{\text{lb}}{10^6 \text{ Btu}}$	
Minimum Decontamination Factor Required	126	107
Outlet load at minimum	.033 gr/scfd	.033 gr/scfd

* (based on 7% moisture)

In order to meet the emission standard, an efficiency of just over 99% is required. For an outlet loading of 50% of the limit, the required removal efficiency would be 99.5%. This efficiency would be considered a design efficiency for any removal system.

A typical size distribution of airborne flyash at an air preheater outlet on a mass basis is shown in Figure 1. This shows that for a pulverized coal fired plant, a significant fraction (here 3.5%) of the particulate mass can be submicron size. Typically, a power plant requires a removal efficiency of over 99% by mass to meet federal emission standards. For this to result, a significant part of the submicron particles must be removed as well as nearly all of the larger particles. Since it is easiest to remove the large particles, present day technology can still adequately accommodate present emission standards by removing the large particles efficiently and allowing a large fraction of the submicron particles to enter the atmosphere.

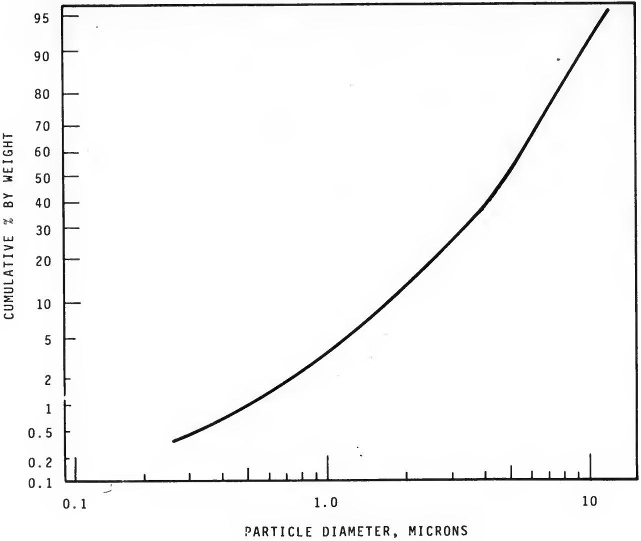


FIGURE 1. Flyash Characteristic Size Distribution From A Pulverized Coal Fired Power Plant(2)

Submicron particles in the 0.1 - 0.3 μ range are the most visible in a plume, are the most difficult size to remove, and represent a significant fraction of particulate pollutants.(3-4) Because of the concern for the effects of submicron particles on health, visibility, plant and animal life, materials, etc., the United States Congress is formulating opinions on what, if any, small particle emission standards should be established. A consultant to concerned congressional committees indicated that a combustion standard for $< 2\mu$ particles emissions could be only 5 years away.(5) This could be of great concern to the power industry shortly if power plants are forced to retrofit submicron particle removal equipment on existing plants. In some cases, retrofitting might be incompatible with existing particulate removal equipment (for example, the high moisture condition produced by a wet scrubber is incompatible with fabric filters without reheating the gas). At this point it might be premature to cause alarm, but it seems appropriate to indicate what future particulate controls the power industry might face. As one evaluates the present state-of-art methods one needs to consider the collection efficiences on submicron particles in terms of future possible emission standards.

Although this study addresses effect of the various methods on the particle size distribution immediately downstream of the particle remover, the actual distribution in the plume leaving the stack can be quite different. Since the stack gas is usually near saturation, the plume is rapidly cooled below saturation immediately above the stack. This condensation process as well as residence time in the stack leads to particle agglomeration. Thus, the particles are then larger than before. The final dispersion of the flyash in the plume throughout the environment is under intensive study presently. Because of the complexity of the dispersion problem, it is difficult to address the state-of-art of flyash removal and adequately consider the final end result of the particles that escape to the environment.

C. Low and High Temperature Electrostatic Precipitation

Electrostatic precipitation has become the most frequently used flyash removal method in the coal-fired power industry. It has been

developed to a point of high reliability and efficiency. Most of the flyash precipitators have been placed downstream from the air preheater and operate near 300°F (low temperature), as opposed to the alternate location ahead of the preheater where they operate around 700°F (high temperature). With the advent of SO_2 emission controls and a switch to low sulfur western coals, high temperature precipitators have come into widespread use.

The main reason for this popularity is that the flyash deposited on the precipitator plates at the high temperature has a sufficiently low electrical resistivity regardless of the sulfur content of the coal. Ash resistivities higher than 2×10^{10} ohm-cm lead to lower precipitator efficiency. For high sulfur coals, SO_3 condensation on the flyash surface lowers resistivity, hence the applicability of low temperature precipitators for high sulfur coal. For low sulfur coals with a probable high variation in that sulfur content, many vendors of precipitators recommend high temperature precipitators.

Bulk electrical resistivity of deposited flyash is its most critical property and, hence, probably the most critical design parameter. The resistivity of flyash depends on its chemical makeup (besides sulfur) and temperature. At 300°F most flyash resistivities are between 10^8 - 10^{12} ohm-cm. 2×10^{10} ohm-cm is often accepted as the acceptable upper limit.(6) If flyash resistivity is too high, a number of undesirable conditions arise:

1. The flyash layer on the walls has a high resistance to the flow of current; hence, a high voltage loss occurs across this layer.
2. With this loss of voltage, the field strength that causes charged particle migration is lowered, thereby lowering the deposition velocity.
3. Current losses due to high resistance reduces the corona current that causes the necessary particle charging.
4. A back corona develops that can result in harmful arcing which shortens the life of the charging wires.

5. The collected dust layer is more difficult to remove due to inordinately high electrical forces between the deposit and the collecting plates.

The combination of these conditions can lead to serious loss of efficiency and operational reliability. Therefore, operating conditions of the precipitator must be such as to insure that the flyash resistivity is below 2×10^{10} ohm-cm.

Figure 2 shows the bulk resistivity of a number of low sulfur western coals as a function of temperature. Some have sufficiently low resistivity at 300°F and could be removed at this low temperature. Their low resistivity might be attributed to adequate (>2%) Na_2O in the ash, but no flyash analyses accompanied the above figure. Few resistivities are unacceptable in the 600 to 700°F range. For this reason about 100 generating units burning low sulfur are now using hot precipators. Many of these are retrofit units.

A curve representing Montana Rosebud coal resistivities is superimposed on Figure 2. This information was supplied by the Montana Department of Natural Resources and Conservation and summarizes two independent series of analyses. The flyash resistivities in the low temperature region around 300°F are definitely problemsome. But at temperatures over 565°F no high resistivity problems should occur for a high temperature precipitator.

Another alternative to high temperature operation is flyash conditioning. The resistivity of the ash can be lowered to an acceptable level by "conditioning" the airborne flyash with continuous injection of SO_3 or H_2SO_4 upstream from the low temperature precipitator. This has been demonstrated to be generally effective(7) and does not create an additional pollution problem, since virtually all the added sulfur condenses on the flyash surface around 300°F. The combustion of high sulfur coal produces adequate (1-3% of the total sulfur) SO_3. The lack of widespread use of this technique is probably due to the nuisance of controlling another operation in the power plant. Operation of a hot precipitator is easier,

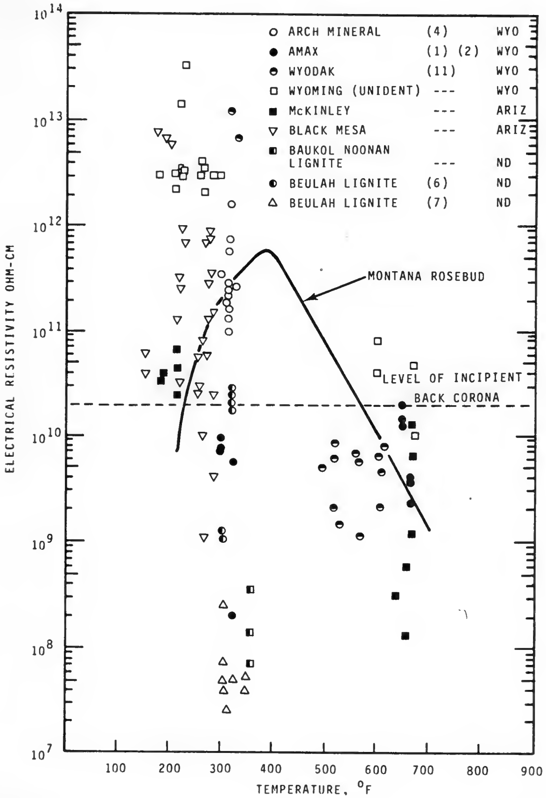


FIGURE 2. In-Situ Bulk Electrical Resistivity Measurements on a Variety of Western Fuels(6)

but not necessarily less expensive. Two precipitator vendors contacted during this study said they recommend hot precipitators as opposed to conditioning because of demonstrated histories of reliability. No vendor would recommend a trial and error research program for a power plant to determine the envelope of operating condition for proper conditioning. Costs of conditioning are estimated at about 1 percent of the total cost of the total power generation cost.(7)

The above discussions indicate that high temperature precipitation is a preferred technique for low sulfur coal flyash removal. However, there is a class of low temperature European precipitators that are considered by their vendors as well as satisfied users to be a definite alternative to high temperature precipitators. In order to compare the U.S. design with the European, it is necessary to now discuss precipitation fundamentals.

A flyash precipitator is composed of a box through which gases are passed by vertical collection electrodes or plates parallel to the gas flow. Discharge electrodes (wires or rods) are supported vertically at regular intervals between the plates. A high negative DC voltage is applied to these electrodes creating corona discharge. The resulting ionized gas molecules charge the particles which can now move toward the collecting plate in the resulting field. Periodically these plates are rapped to dislodge the particle layer. The layer falls into a bin which is regularly emptied into a pneumatic handling system.

The domestic design is basically a series of two-point suspension parallel plates with small riblike turbulent inducing baffles at regular intervals. The negative electrodes are usually 30-foot long hanging cylindrical wires with heavy weights at the bottom ends. In the flow direction the plates are insulated from each other, so that voltages can be individually controlled at each plate section or "field." Rapping is usually done at the top of the suspension and not on the plates directly. The maximum vertical dimension is about 35 ft because electrical forces on the hanging wires cause intolerable wire motion for larger distances. The hanging wires also can short out (and shut down) a section of the

precipitator after breaking, usually from spark erosion. These wires are easy to replace, and down time from wire breaks is short. Because of the simplicity of the domestic design it is less expensive to purchase than the European design, and it has been a popular choice for use as a hot precipitator, particularly for retrofit situations.

The European import seems to be a more sophisticated design. The attention to minute details here has given this product the capability to operate as a low temperature precipitator for high resistivity ash. Some of the design features that were stressed by a vendor are:

1. Frequent and strong rapping of the deposition electrodes directly. This is the essential feature that minimizes the influence of the high resistance ash layer. A rapping energy per unit mass of 100 g's is provided at each rap.
2. Negative discharge electrodes are short (5') and rigidly supported at top and bottom. This minimizes electrode drift toward the deposition electrode and thus sparking losses are kept at a minimum. There is virtually no limit to the vertical height of precipitators using layers of these five foot electrodes and frames.
3. The discharge electrodes are usually four cornered stars. Each corner is almost a tiny cylinder in cross-section which facilitates discharge. One type of discharge electrodes has many pointed pimples on its surface to do the same thing.
4. All the discharge electrodes are evenly spaced, usually 6 in. apart, whereas the hanging wire types have a vacancy at every third position to accommodate the turbulence inducing baffle.
5. There is virtually no "sneakage" of gas around the electrode regions.
6. The deposition electrodes are supported at four points rather than two, giving more rigidity to the system.

7. Gas flow minimizes reentrainment and aids deposition. This is accomplished by depressing regions in the deposition plates creating quiescent zones at regular intervals.
8. No dead gas pockets exist where dust can build up and short out any fields.

The European design can be used at high temperatures as well as low but costs slightly more at the high temperature. This is due to added costs of ducts and insulation. The ash deposition rate is higher at the high temperature, but the increased gas volumetric flow cancels this advantage. The European version for low temperatures costs about 15% more than the domestic for high temperatures because the European is usually bigger for the same application.

In summary, we conclude the high temperature and low temperature electrostatic precipitation can adequately remove more than 99.5% of the initially airborne flyash. The 0.5% that escapes has a smaller mass average size than the initial airborne flyash and has a large fraction of submicron particles (Figure 3). Comparing Figures 1 and 3 show that the precipitator inlet mass average size is 5 micron and outlet is 2 micron. Thus, if submicron emission standards are imposed in the future, precipitators alone might not be able to provide adequate cleanup capability.

D. Baghouse Filter Systems

Filtration technology has advanced to the point where its application to the coal-fired power plant seems feasible. Development of filtration materials that withstand the temperatures and corrosive nature of flue gas are the accomplishments that make flyash filters possible. Baghouse filters have been successfully employed in tens of thousands of industries worldwide, but only one application has been made on a coal-fired power plant that has demonstrated one year of successful operation.(8)

This application is only modest in size (two 80 MW units). The Sunbury Steam Electric Station 45 miles north of Harrisburg, Pennsylvania, burns low sulfur anthracite and the low resistivity of the ash gave low efficiencies in early electrostatic precipitators. Now, after one year of

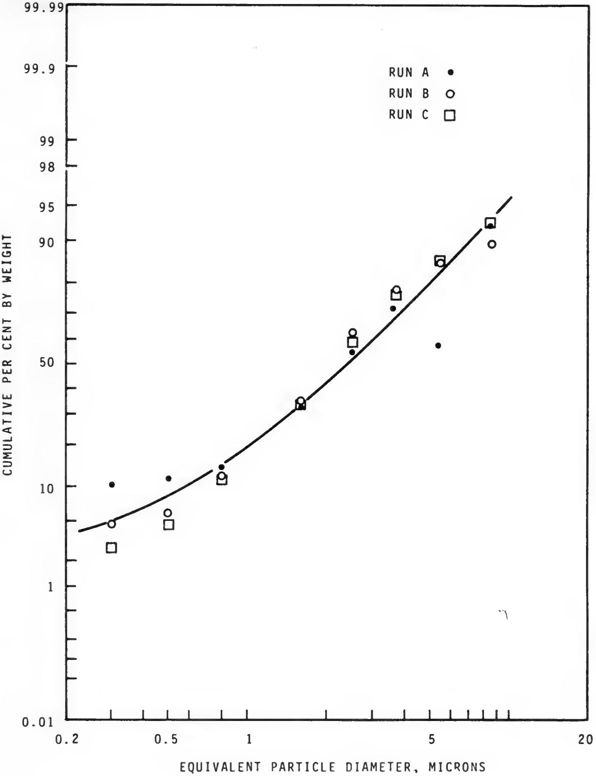


FIGURE 3. Typical Flyash Size Distribution at a Precipitator Outlet

operation, some bag wear was noticed; but in general greater than 99.5% removal efficiency was constantly demonstrated at a stable 2 1/2 - 3 inches H_2O pressure drop. The fiber material for the bags is a teflon coated fiberglass suitable for the 340°F inlet temperature. Cost of the installation was $5.5M ($3.3M for the baghouses) and first year maintenance was about $60K. Power costs are omitted from these figures. With this successful demonstration it seems necessary to include baghouses as an alternate in this study.

Since the baghouse offers a serious choice for flyash removal, and if emission standards for particles get tougher, baghouses might become the most efficient per dollar of capital expenditure. This would be more certain if the costs of SO_2 control are included. New developments in the use of dry natural sodium bicarbonate (nahcolite) indicates that the baghouse system has promise for SO_2 control.(9) Using a dry absorber such as this would add little to capital investment and might be economically attractive on coals having less than about 1.5% sulfur. Certainly this method is not without problems. The location of much of the available nahcolite is in the oil shale regions of the west and its long-term availability is questioned. Too, the disposal problem of the soluble sodium sulfite and sulfate has not been solved. However, the development is worth watching in the future and it could give baghouses a share in the utility market.

The technical aspects of baghouses are elaborated on in the following paragraph. The basic filtration mechanism involves particle capture by the layer of particle fines and not by the fabric fibers. Clean unused bags are not highly efficient. Filtration efficiency usually increases as loading increases, and a filter bag is not cleaned until the flow rate decreases to an undesirable point. The actual efficiency of the fabric filter heavily depends on cleaning mechanisms and cycles, particle size and gas velocity. The effect of loading and cleaning is shown in Figure 4. Here some tests were run on clean, loaded (∿15μ flyash) and fabric shaken partially clean. Test aerosols were monodispersed. A new clean filter showed maximum penetration, and a flyash laden filter

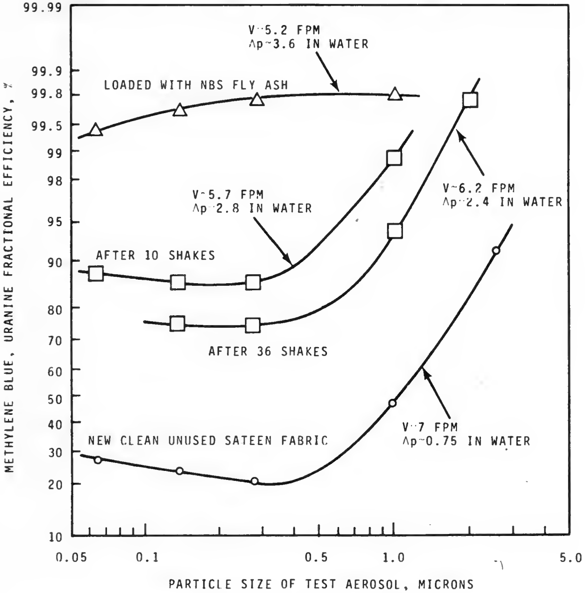
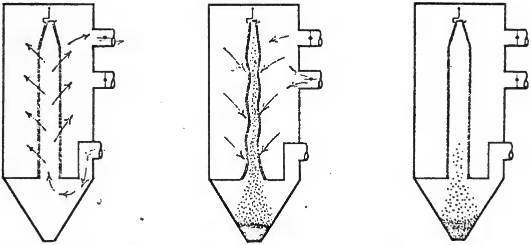


FIGURE 4. Fractional Efficiency of Collector-NBS Flyash Layer on Cotton Sateen Using Methylene Blue and Uranine Test Aerosols (From Whitby and Lundgren, Ref. 10)

displayed actually $\geq$ 99.5% efficiency for all particles including submicron particles. After shaking the efficiency fell off somewhat. At plant operating conditions only a fraction of the parallel filter units are at the shaken clean stage. Even these can operate at greater than 90% on even the most penetrating submicron particles (0.1 - 0.3μ). So one can anticipate that under normal correct operating conditions to get a conservative lower bound on submicron particle removal efficiency of 90%,(11) and an overall weight efficiency of 99.9% on the initial flyash.

A typical utility baghouse system would consist of a large number of modules containing the filters. This modular concept is necessary to maintain steady flow and pressure drop across the total system. There will always be a certain number of the modules undergoing some phase of cyclical cleaning. Too, if trouble occurs in a module or if periodic maintenance of the module is necessary, it can be conveniently isolated from the system without shutting the system down. The modular concept also makes it possible to construct additional modules if necessary and makes it convenient from the engineering design concept. To scale up the filter package from a small to a large plant an engineer needs to simply add more filter modules. Of course the exterior ductwork and fans are not modularized.

The operating cycle of a baghouse is quite simple. For large gas volumes such as in a power plant, minimizing the pressure drop is desirable. This necessitates a large flow rate (acfm) to filter area (ft^2) ratio and reduces the number of choices of cleaning methods. The usual design velocity is about 2 ft/minute and a preferred cleaning method is reverse flow (repressurising) followed by shaking. Figure 5 illustrates the operating cycle of a module. Each module consists of an array of vertical cylindrical fiber filter bags. During filtration the bags are fully inflated. A flow meter monitors the flow and triggers the cleaning operation when the flow rate is reduced to a preassigned value. Reverse flow collapses the bag and along with shaking, the dust layer falls into the hopper for disposal. Filtration resumes to complete the cycle. During normal operation the cloth pressure drop is 3 - 4 inches H_2O.



FILTERING REPRESSURING SHAKING

Figure 5. Typical Baghouse Module Operating Cycle

The unique physical feature of the large utility baghouse would be its size. "Huge" may be an insufficient adjective. For a 700 MW unit such as Colstrip 3 or 4 handling 3.2×10^6 acfm at 300°F, 1.6×10^6 ft^2 of filter surface are needed. To house this 1.8×10^6 ft^3 of volume space is needed. Such a system might be typically 65' high, 90' wide and 300' long. Two units side by side would overlap by 10' each side of the inbound goal-line-to-goal-line playing surface of a U.S. football field. So in determining the feasibility of each large utility baghouse, the land consumed is a major consideration, and this single fact might be the reason why no very large flyash units have been built.

Cost comparison for a baghouse system on a plant on the order of 500 MW size show that on a capital investment basis, baghouses cost about the same as a hot precipitator ($25/kw). This would make the capital investment about $18M for each Colstrip unit. Operating costs would be slightly higher for the baghouses, primarily in bag replacement and fan power costs. Maximum bag life is considered as two years.

From the above discussions, we conclude that the large utility baghouse has no economic advantage over other alternatives with present particle emission standards, and its huge size might be a deterrent to choosing it. However, it does appear to offer the most efficient practical submicron particle removal capability available today. The baghouse does have some potential for low level SO_2 removal, and if submicron emission standards are established in the future, it might become very competitive.

E. Wet Scrubbers

Wet scrubbing to remove airborne particles is a relatively new technique. Most wet scrubber systems are incapable of removing small airborne particles especially those in the .1-.3μ range. These particles have little inertia and little Brownian motion and thus do not tend to migrate toward a wet surface or depart from their velocity streamline when approaching a wet submerged object. When the high energy scrubbers arrived, a new technology for removing particles was available. Today the venturi is the workhorse of the particulate wet scrubbers.

This type of scrubber uses a high velocity gas stream to atomize water and accelerate the resulting droplets. While these droplets are accelerating, a relative velocity exists between the flyash particles and the droplets. This relative velocity causes direct impaction to occur resulting in collection. The converging part of the venturi accelerates the dirty gas. Water is injected in the throat of the venturi through the walls or by flooding a circular disc near the throat entrance. The shear forces create the droplets which are collected downstream in a cyclone or mist eliminator. The Colstrip 1 and 2 scrubbers depend on adequate contact time between drops and gas to absorb SO_2. This is done by having a large holdup volume upstream from the mist eliminator. The efficiency of particle removal depends primarily on two parameters; the venturi pressure drop and the liquid/gas flow ratio. These parameters are usually considered to remain constant in scaling up venturi size, such as in the Pilot Plant study (Reference 1) by Combustion Equipment et al.

This pilot program was significant in proving the capability of adequate SO_2 control for Colstrip Units 1 and 2. At the same time valuable information on particulate cleanup was obtained. This 3000 acfm pilot plant used Corette Station flue gas having an average dust loading of 2 grains/scfd. Pressure drop and liquid/gas (L/G) flow ratio were varied and were maintained along with a constant gas velocity. Figure 6 shows that collection efficiency increased as pressure drop was increased; but the effect of a variable L/G is not as clear from the data. The authors have decided that for an L/G of 15 and $\Delta P = 17$ in. water, adequate scrubbing occurs for the emission standards to be met with Colstrip Units 1 and 2. The data shows a 99% reduction in airborne flyash from 2 to .02 grain/scfd.

As indicated earlier in the discussion about Table 1, the average emission grain loading that meets the federal standard is 0.033 grams/scfd. This is for an average inlet loading of about 4 grains/scfd, which is the expected average for the Colstrip plants. To meet the federal standard, somewhat greater than 99% efficiency is needed and this has not been clearly demonstrated in the pilot program. One cannot rule out the possibility that 99.5% is an attainable efficiency. This could be reached if, at higher grain loadings of $\gtrsim 4$ grains/scfd, the particle distribution contains a higher percentage of the heavier particles that are easily removed. This seems to be the expectation of the authors in extrapolating the pilot study of data to the full plant scale, a 500 fold increase in capacity. A series of stages might accomplish the desired level, but only with added capital and operating costs.

In Figure 7, the average fractional collection efficiency is plotted versus particle size. A curve is drawn through the data at $\Delta P = 17$ in. H_2O. There is a marked difference in penetration of submicron versus the larger particles. Over 10% of the smallest measured submicron particles can get through the scrubber at the condition of L/G = 15 and $\Delta P = 17$ in. H_2O. This contrasts about to 0.1 - 0.2% penetration of the particles over 4μ. Very little is gained by expending more energy (higher ΔP) as shown on Figure 7 to remove more particles. So, it appears

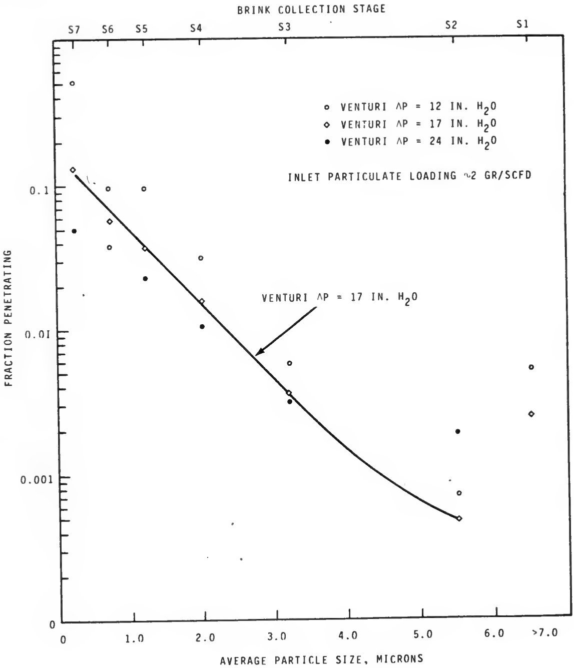


FIGURE 7. Scrubber Fractional Collection Efficiency - Test Series 300(1)

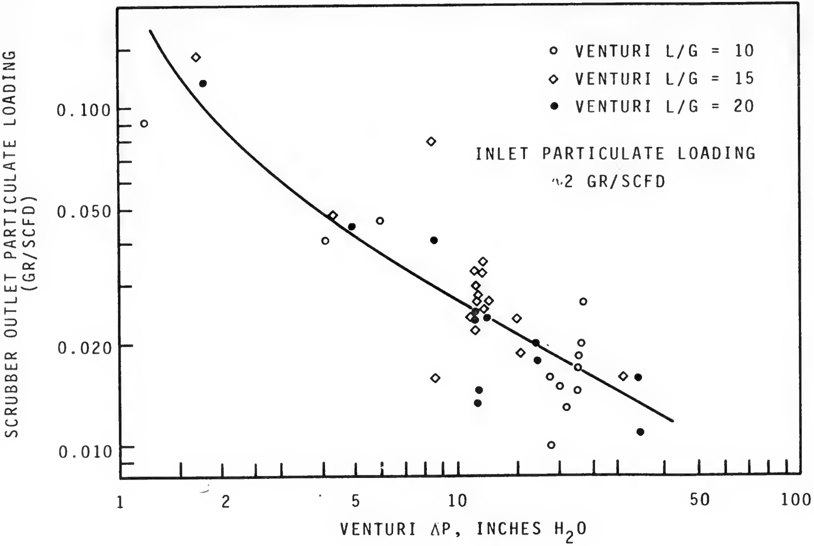


FIGURE 6. Outlet Particulate Loading Versus Pressure Drop and L/G - Test Series 200 and 300(1)

that the practical attainable maximum efficiency of the scrubbers is 99.5%. This number is deduced from a virtually 100% removal of the large half of expected airborne flyash and 99% removal on the remaining half. A significant increase in efficiency in the full scale scrubbers cannot be counted on, so we are concerned that the full scale scrubbers for Colstrip 1 and 2 will operate without a demonstrated safety margin for particulate emissions.

Probably one of the most successful venturi scrubber operations in the coal-fired utility industry is at the Dave Johnston Plant at Glenrock, Wyoming.(12) They are presently operating at about 99% efficiency at $\Delta P = 10$ in. H_2O. The scrubber outlet loading is guaranteed not to exceed 0.04 grain/scfd. This is not adequate for the Colstrip plants. However, they have had a number of problems. The most serious problems are those that result in lower power levels or actual shutdown. Experience with scrubbers in the industry, in general, has been somewhat disappointing resulting in considerable reductions in plant availability. The Dave Johnston Plant claims to have 80 - 90% utilization with its three scrubbers. They manage to operate a closed loop operation with its scrubbing water-settling-pond system except for about one month a year. During this month inadequate pond evaporation occurs when fresh water is trickled into the venturi to dissolve scaling. This causes the pond to overflow into the Platte River. Other problems included flyash buildup at wet/dry surface boundaries. Also, since the stack gases are not preheated, some mist drops fall out of the plume in the plant area. Some more problems with scrubbers are discussed in the SO_2 section of this study.

Other high energy wet scrubbers have been tried including a scrubber cell full of ping-pong ball size hollow plastic balls.(13) Liquid falls down through the bed and the flue gas is forced up countercurrent to the liquid flow. A high pressure drop mobilizes the balls. Sufficient agitation occurs to keep flyash from building up and this agitation is necessary to scrub out particles. Efficiencies reported to date do not get as high as 99%. Also, ball attrition losses were high.

Recent developments in venturi scrubbing may well lead to improved efficiencies. Steam introduced into a venturi throat aids in particle agglomeration during condensation. Condensation could be expected in normal venturi operation in coal plants. The spray drops cool the flue gas below the dew point. During condensation flyash particles are agglomerated onto the mist particles. These larger particles can then impact easier with the atomized drops. Adding more steam should increase this agglomeration phenomena. This is one example of an operational improvement that might be expected in future years with wet scrubbers. Scrubber technology today is rapidly improving, so the state-of-the-art might be significantly different in a few years.

High energy wet scrubbers probably have the lowest capital costs of all four techniques discussed in this study (15K$/KW for venturis on a 500 MW plant). This is about 60% of the precipitator or baghouse cost. Space requirements are small. However, operating costs can be fairly high. The cost of fan power and chimney reheating make it about the most expensive to run. If loss in power revenues due to operational difficulties are significant, this single item can overwhelm other costs. This is why operational reliability is such an important item. Wet scrubbers have been less reliable than the other methods. The auxiliary equipment such as valves, pumps, lines, etc. have been very vulnerable to flyash erosion.

In spite of the apparent problems still plaguing utility scrubbers, they might be capable of working reliably and at the desired 99.5% efficiency. The present day scrubber does as well as electrostatic precipitators on submicron particles. The outlet size distribution is nearly the same. Coupled with adequate capability for meeting present SO_2 emission standards, they do become an attractive alternate choice for low sulfur coal plants.

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IV. TRACE ELEMENTS

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IV. TRACE ELEMENTS

A. Introduction

In 1970 the U.S. consumed approximately 550 million tons of coal, 65% of which was used for electricity generation. Combustion of such large quantities of coal could potentially contaminate the natural environment with minor coal constituents released during the combustion process. In regions such as Montana where projections indicate the development of large coal-electric generating capacities the concern of possible environmental insult is valid. Furthermore, the ever widening construction of large (1000 MWe and greater) coal-electric generation facilities, which combust millions of tons of coal per year, forces an enlarged look at the overall increase of plant emissions. Although these plants release low concentrations of toxic trace elements over the operating lifetime of the facility, the accumulated trace elements may contaminate the surrounding environment. As an example, the projected Colstrip unit(1) will consume 585,300 lb of coal/hr which is equivalent to $\sim 2.5 \times 10^6$ tons/yr. If a trace contaminant such as selenium or arsenic is present in the coal at only 1 ppm, 2.5 tons/yr of these contaminants will be burned in the coal.

Recent work has shown that trace elements found in coal can occur in both gaseous and particulate forms of combustion effluents (90% of mercury appears to be lost as vapor).(2,3) It also appears that many of the potentially hazardous elements (for example, selenium, arsenic, lead, cadmium, and vanadium) preferentially concentrate upon the finest particulate fractions in the combustion effluents stream.(4,5) Since both the gaseous and the finest particulate fractions at present are inefficiently removed from combustion effluents, there is concern about the fact of the hazardous trace contaminants.

With these facts at hand, we have undertaken to evaluate the trace element emissions from the projected Colstrip facility. This evaluation will consider both particulate and gaseous forms of the various elements.

The differentiation between particulate and gaseous particles is somewhat arbitrary, since condensation occurs continuously between the fire box and the release from the stack. Our goal in this effort is to indicate:
1) forms and distribution of the trace elements which may occur during plant operation, 2) the method which appears to give optimum control of trace element emissions, and 3) potential areas of concern.

B. Particulate Trace Element Emissions

Relatively little is known about the nature or size distribution of particulate emissions from coal-fired power-generating plants. A literature assessment was conducted to estimate the size distribution of particles arising in combustion of coal and the effect of dust-removal devices on this particle size distribution. Three different techniques for particle emission control were considered including fabric filtration, electrostatic precipitation, and Venturi scrubbing. The assessment of trace element emissions is based on the following:

- The particle size distribution considered in this investigation was the observed distribution in a pilot plant study(6) conducted by Combustion Equipment Associates, A. D. Little and York Research for the Colstrip Generating Station of Montana Power Company; see Figure 1.
- An efficiency curve for Venturi scrubbing was calculated using the input and output data of the pilot study; see Figure 2.(6)
- An efficiency curve for electrostatic precipitation was compiled using data from one representative precipitator studied in reference 7; see Figure 3.
- An efficiency curve for fabric filtration was estimated from data supplied in Handbood of Fabric Filter Technology;(8) see Figure 4.
- The chemical composition versus particle size was taken from data(5) shown in Table 1 and obtained in previous work at our laboratory. Figures 5 and 6 show the variation of chemical composition with particle size for selected elements from Table 1. Samples I, II, and III in these figures are from three different power generating facilities.

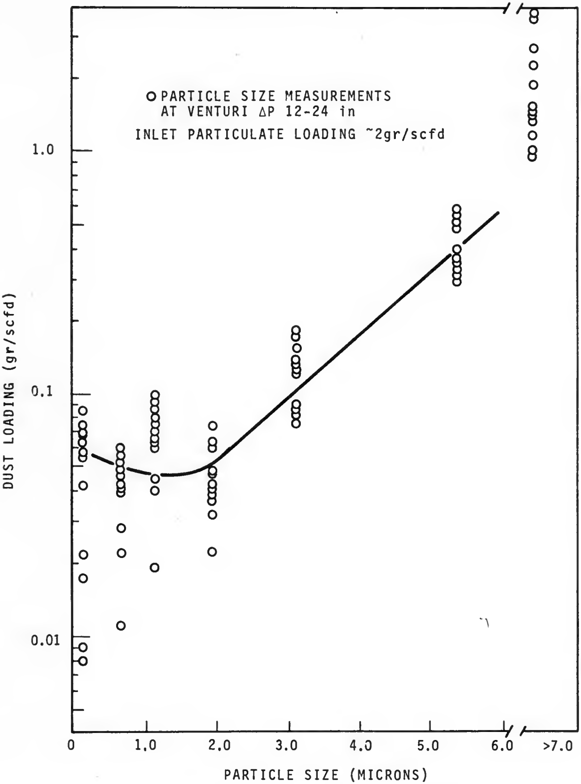

FIGURE 1. Inlet Particle Size Distribution (Compiled from data in Reference 5)

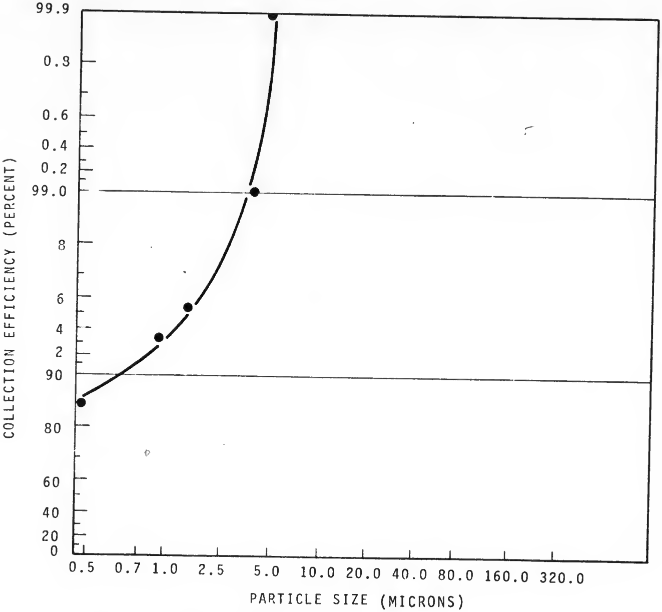

FIGURE 2. Computed Efficiency Curve for Flyash Removal by Venturi Scrubbing (Compiled from data in Reference 6)

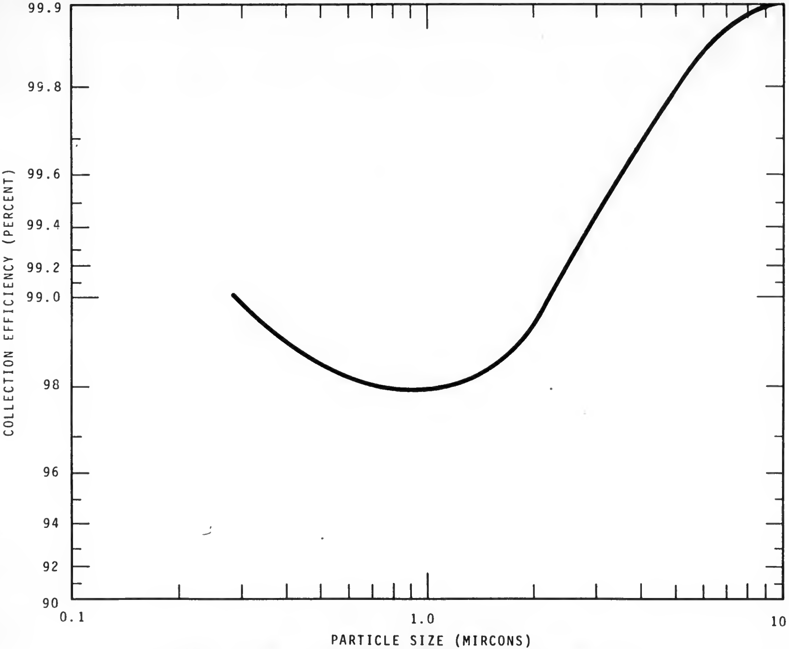

FIGURE 3. Computed Efficiency Curves for Flyash Removal by Electrostatic Precipitation

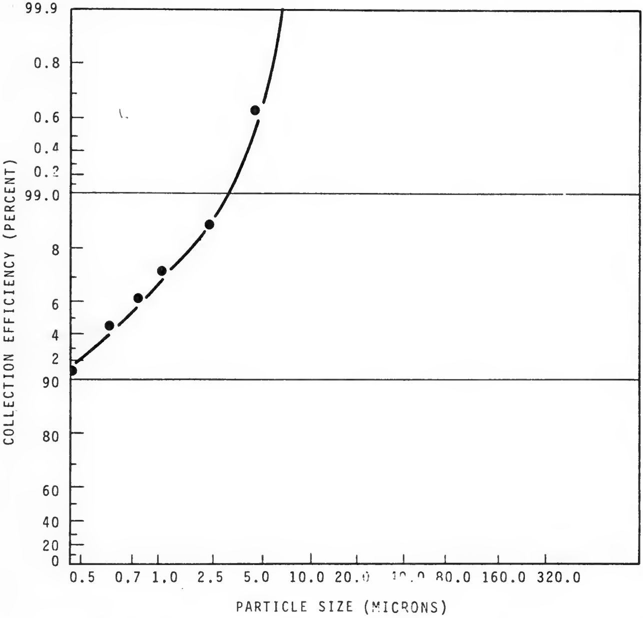

FIGURE 4. Computed Efficiency Curves for Flyash Removal by Fabric Filtration (Computed from data in Reference 8)

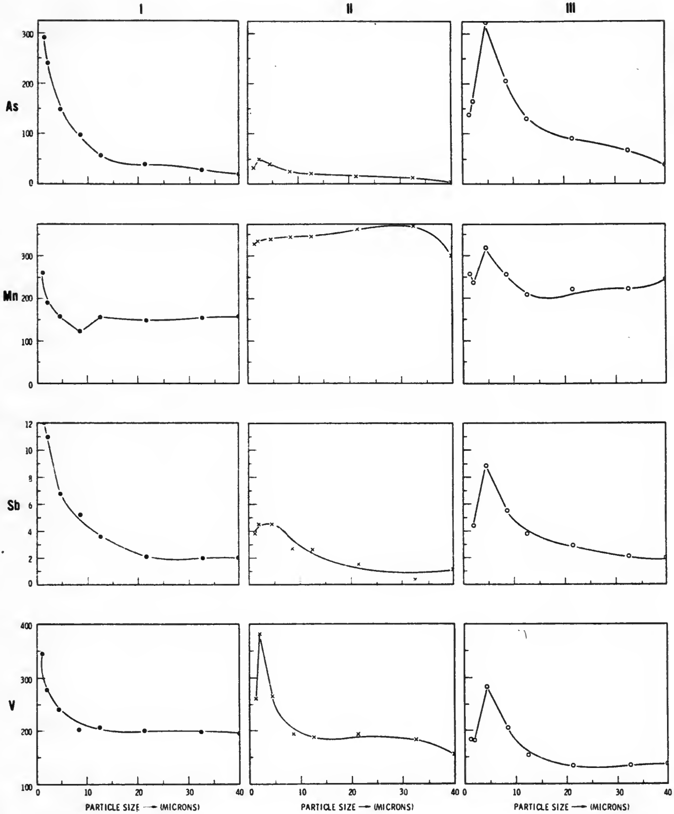

FIGURE 5. Elemental Composition of Flyash from Three Selected Power Plants as a Function of Particle Size (ppm except as noted)

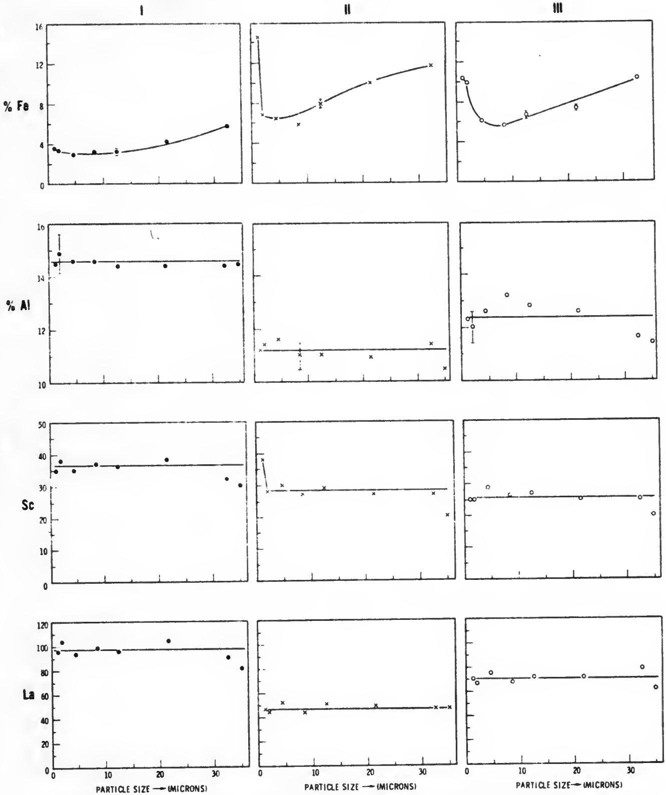

FIGURE 6. Elemental Composition of Flyash from Three Selected Power Plants as a Function of Particle Size (ppm except as noted)

TABLE 1. Elemental Composition of Flyash as a Function of Particle Size (ppm except as noted)

PARTICLE SIZE (MICRON)	Al (%)	As	Ba	Br	Cl (%)	Co	Cr	Cs	Cu (%)	Eu	Fe (%)	Hf	Hg	K (%)	La	Mn	Na (%)	Rb	Sc	Sb	Se	Sm	Sr	Ta	Tb	Th	Ti (%)	V
1.28	14.5	291	1660	5.1	<0.1	68	978	16	<0.05	2.5	3.55	11	5.6	3.08	95	270	0.38	12	35	12	18	15.3	2020	4.0	2.1	31	0.88	345
2.03	14.9	240	1820	7.6	<0.1	69	890	15	<0.05	2.9	3.33	10	0.52	3.35	103	189	0.41	13	38	11	10	16.3	2590	4.4	2.0	35	0.82	277
4.55	14.6	148	1420	2.9	<0.1	56	488	14	<0.05	2.6	2.93	8.9	-	3.22	93	157	0.38	9	35	6.8	14	14.7	1670	4.2	2.1	32	0.79	240
8.45	14.6	97	1640	8.2	<0.1	45	367	13	<0.05	2.5	3.20	10	2.0	3.51	98	122	0.40	12	37	5.2	15	15.8	1640	4.4	2.0	37	0.85	201
12.6	14.4	57	1640	8.0	<0.1	34	335	11	<0.05	2.9	3.19	10	-	3.15	95	156	0.37	13	36	3.6	4.6	16.1	1750	4.2	1.7	33	0.79	207
21.6	14.4	40	1640	-	<0.1	31	428	12	<0.05	3.0	4.20	11	-	3.36	104	148	0.36	12	38	2.1	14	16.8	1940	5.0	2.4	36	0.80	199
32.5	14.5	28	1420	0.50	<0.1	27	349	12	<0.05	2.4	5.77	10	2.0	3.14	89	156	0.34	11	32	2.0	-	14.7	1730	4.2	1.4	31	0.78	197
>32.5	14.8	20	1330	-	<0.1	26	341	12	<0.05	2.6	9.32	11	-	3.36	90	158	0.33	11	30	0.53	8.7	13.8	1270	4.0	1.5	29	0.88	193
1.28	11.2	32	930	0.13	<0.1	47	289	19	<0.05	2.6	14.52	12	3.0	1.97	47	328	0.65	8	38	3.8	20	9.7	670	3.9	1.9	33	0.62	260
2.03	11.4	49	220	-	<0.1	41	261	17	<0.05	2.0	6.83	8.1	3.6	2.38	45	334	0.77	8	28	4.5	18	10.2	-	3.3	1.5	23	0.66	382
4.55	11.6	40	1020	4.0	<0.1	40	224	19	<0.05	2.4	6.49	6.2	1.2	2.41	52	339	0.82	10	30	4.5	15	10.6	-	3.1	1.5	25	0.62	265
8.45	11.0	24	250	-	<0.1	30	160	14	<0.05	1.9	5.82	8.1	1.9	2.06	44	344	0.71	11	27	2.7	14	9.6	-	3.0	1.6	22	0.62	193
12.6	11.0	20	590	3.8	<0.1	27	163	14	<0.05	2.2	7.90	7.0	2.2	1.97	51	344	0.69	9	29	2.6	11	10.8	-	2.9	1.4	24	0.57	188
21.6	10.9	15	350	-	<0.1	27	157	12	<0.05	2.1	9.96	7.2	4.1	2.25	49	363	0.58	8	27	1.5	4.7	9.8	-	3.3	1.8	21	0.66	193
32.5	11.4	13	890	0.25	<0.1	28	150	12	<0.05	1.7	11.71	8.0	2.4	1.91	47	370	0.57	8	27	0.37	4.8	10.5	350	2.8	1.3	23	0.61	181
>32.5	10.4	6.1	500	6.5	<0.1	25	116	9.5	<0.05	1.3	15.98	5.6	1.1	1.93	47	301	0.41	9	20	1.1	3.2	8.6	-	2.0	1.3	15	0.57	157
>32.5 (MAGNETIC)		5.2	560	2.4		50	142	2.9		1.1	44.06	3.1	2.2	0.82	23		0.21	5	15	0.77	2.1	5.8	-	1.3	0.84	13		
>32.5 (NON-MAGNETIC)		5.5	750	0.66		16	116	12		1.4	4.57	6.8	1.9	2.44	56		0.49	6	24	1.2	8.8	9.5	560	2.7	1.5	19		
1.28	12.3	139	1170	1.5	<0.1	29	142	12	<0.05	1.8	10.34	7.0	0.50	2.48	70	256	0.59	8	25	4.1	6.4	11.3	1370	3.3	1.4	18	0.57	183
2.03	12.0	165	1340	7.4	<0.1	30	144	11	<0.05	2.1	9.93	7.2	1.8	2.15	67	235	0.60	8	25	4.4	9.6	11.4	1880	2.9	1.4	22	0.53	182
4.55	12.6	322	1900	-	<0.1	40	216	16	<0.05	2.0	6.11	8.4	0.81	2.88	75	317	0.71	9	29	8.8	16	11.1	1780	3.7	1.7	20	0.68	282
8.45	13.2	206	1110	4.5	<0.1	30	147	12	<0.05	2.1	5.65	7.0	-	2.54	67	255	0.69	7	26	5.5	8.5	11.5	1850	3.1	1.2	22	0.68	204
12.6	12.8	131	1610	3.1	<0.1	27	138	11	<0.05	1.7	6.73	8.0	-	2.59	71	208	0.63	6	27	3.8	8.3	11.3	2220	3.5	1.7	19	0.68	154
21.6	12.6	92	1050	-	<0.1	23	114	10	<0.05	2.0	7.39	7.6	-	1.87	70	221	0.59	8	25	2.9	7.0	11.5	2210	3.2	0.69	22	0.65	136
32.5	11.6	68	830	9.1	<0.1	26	124	7.4	<0.05	1.9	11.39	8.0	4.1	2.51	78	219	0.55	7	25	2.1	7.8	11.9	1960	3.3	1.6	19	0.61	135
>32.5	11.4	39	1530	3.3	<0.1	24	101	8.7	<0.05	1.7	14.34	6.7	0.81	2.02	62	246	0.44	7	20	2.0	9.8	10.5	1370	2.3	1.2	18	0.56	138

To assess the relative removal of each trace element for each device, Distributions I and III (Figures 5 and 6) of chemical composition versus particle size were used. Both distributions were obtained from analyses of sized particulate matter collected from the operating coal combustion electric generating facilities mentioned above. These distributions are included in Figures 5 and 6 as Columns I and III. For example, one distribution has peak arsenic concentrations on particles of less than 1 μm in diameter. The other distribution has peak arsenic concentrations at approximately a 5-μm particle size. For the purpose of illustration we will consider the effect of the abatement techniques on arsenic and selenium, while the application to other elements will be discussed later in this document.

The two source terms of arsenic and selenium are listed in Tables 2 and 3. The second column of each table is the mass distribution of particulates taken from Figure 1,(6) while the measured concentration distributions of arsenic and selenium are listed in the fourth and fifth columns.(5) From these data, the two mass distributions (sixth and seventh columns) were computed. In these and subsequent calculations we assumed that removal processes do not change the concentration distribution versus particle size for arsenic, selenium or any other elements.

Tables 4, 5, and 6 show the output distributions from the three control devices for Distribution I with peak concentrations at a particle size of less than 1 μm. Note that the distribution of arsenic and selenium changes completely when passing through the control devices. At the inlet almost half of these elements were on the particle size range of 5 to 6 μm. However, at the outlet one half of the particulate arsenic and selenium are on the size range of less than 1 μm and ∿85% on particles less than 3 μm in diameter. The data also indicate that the average concentrations of arsenic and selenium are actually higher in the outlet particulates than in the input particulates (see Table 2). This phenomenon occurs because the finer particles (∿1 μm), having the highest concentrations of arsenic and selenium, are inefficiently removed by the control technologies relative to the larger

TABLE 2. Distribution I - Source

Particle Size (microns)	g/SCF[a]	wt% of Particulates in Size Fraction	Conc. (μg/g)[b]		Weight Contribution (μg) of Size Fraction to Total		Percent of Total in Size Fraction	
			As	Se	As	Se	As	Se
<1	0.0034	5.7	340	21	19	1.2	11.3	7.3
1-2	0.0031	5.2	270	20	14	1.0	8.1	6.1
2-3	0.0045	7.5	219	18	16	1.3	9.5	7.9
3-4	0.0084	14.0	183	17	26	2.4	14.9	14.6
4-5	0.0149	24.8	156	16	39	4.0	22.5	24.4
5-6	0.0259	43.0	134	15	58	6.5	33.5	39.6
TOTALS	0.0602	100.2			172	16.4	99.8	99.9

Average Concentration	172×10^{-6} g As/g flyash	16.4×10^{-6} g Se/g flyash
	10.3×10^{-6} g As/SCF air	0.99×10^{-6} g Se/SCF air

(a) Inlet distribution compiled from data in Reference 6.

(b) Determined from Figure 5 and Table 1.

TABLE 3. Distribution III - Source

Particle Size (microns)	g/SCF[(a)]	wt% of Particulates in Size Fraction	Conc. (µg/g)[(b)]		Weight Contribution (µg) of Size Fraction to Total		Percent of Total in Size Fraction	
			As	Se	As	Se	As	Se
<1	0.0034	5.7	89	5.0	5	0.29	2	2
1-2	0.0031	5.2	144	7.8	7	0.41	3	3
2-3	0.0045	7.5	200	10.6	15	0.80	6	6
3-4	0.0084	14.0	254	13.0	36	1.82	14	14
4-5	0.0149	24.8	304	15.4	75	3.82	29	29
5-6	0.0259	43.0	274	14.3	119	6.15	46	46
TOTALS	0.0602	100.2			257	13.25	100	100

Average Concentration 257×10^{-6} g As/g flyash 13×10^{-6} g Se/g flyash

15.4×10^{-6} g As/SCF air 0.8×10^{-6} g Se/SCF air

(a) Inlet distribution compiled from data in Reference 6.

(b) Determined from Figure 5 and Table 1.

TABLE 4. Distribution I - Fabric Filter

Particle Size (microns)	% Efficiency	g/SCF(a)	wt% of Particulates in Size Fraction	Conc. (μg/g)(b)		Weight Contribution (μg) of Size Fraction to Total		Percent of Total in Size Fraction	
				As	Se	As	Se	As	Se
<1	90	0.00034	44.2	340	21	150	8.8	56	46
1-2	95	0.00016	20.8	270	20	56	4.2	21	22
2-3	98	0.00009	11.7	219	18	26	2.1	10	11
3-4	99	0.00008	10.4	183	17	19	1.8	7	9
4-5	99.5	0.00007	9.1	156	16	14	1.5	5	8
5-6	99.9	0.00003	3.9	134	15	5	0.6	2	3
TOTALS		0.00077	100.1			270	19.0	101	99

Average Concentration 270 x 10^{-6} g As/g flyash 19 x 10^{-6} g Se/g flyash
0.21 x 10^{-6} g As/SCF air 0.015 x 10^{-6} g Se/SCF air

(a) Inlet distribution compiled from data in Reference 6.

(b) Determined from Figure 5 and Table 1.

TABLE 5. Distribution I - Electrostatic Precipitator

Particle Size (microns)	% Efficiency	g/SCF[(a)]	wt% of Particulates in Size Fraction	Conc. (μg/g)[(b)]		Weight Contribution (μg) of Size Fraction to Total		Percent of Total in Size Fraction	
				As	Se	As	Se	As	Se
<1	98.2	0.00006	21	340	21	71	4.3	31	24
1-2	98.2	0.00006	21	270	20	57	4.2	25	23
2-3	99.2	0.00004	14	219	18	31	2.5	14	14
3-4	99.6	0.00003	10	183	17	18	1.7	8	9
4-5	99.7	0.00005	17	156	16	26	2.7	12	15
5-6	99.8	0.00005	17	134	15	23	2.6	10	14
TOTALS		0.00029	100			226	18.0	100	99

Average Concentration 226×10^{-6} g As/g flyash 18.0×10^{-6} g Se/g flyash

0.066×10^{-6} g As/SCF air 0.005×10^{-6} g Se/SCF air

(a) Inlet distribution compiled from data in Reference 6.

(b) Determined from Figure 5 and Table 1.

TABLE 6. Distribution I - Venturi Scrubber

Particle Size (microns)	% Efficiency	g/SCF(a)	wt% of Particulates in Size Fraction	Conc. (μg/g)(b)		Weight Contribution (μg) of Size Fraction to Total		Percent of Total in Size Fraction	
				As	Se	As	Se	As	Se
1	90	0.00023	41.2	340	21	140	8.7	54	46
1-2	94	0.00008	14.3	270	20	39	2.9	15	15
2-3	96	0.00007	12.5	219	18	27	2.3	11	12
3-4	97	0.00006	10.7	183	17	20	1.8	8	9
4-5	98	0.00006	10.7	156	16	17	1.7	6	9
5-6	99.5	0.00006	10.7	134	15	14	1.6	6	8
TOTALS		0.00056	100.1			257	19.0	100	99

Average Concentration	257×10^{-6} g As/g flyash	19×10^{-6} g Se/g flyash
	0.14×10^{-6} g As/SCF air	0.011×10^{-6} g Se/SCF air

(a) Inlet distribution compiled from data in Reference 6.

(b) Determined from Figure 5 and Table 1.

particles. This distribution leads to less efficient overall removal of many trace elements. Table 7 summarizes the total particulate and single element removal efficiencies for the three control devices. The results in this table show that the elements arsenic, bromine, chromium, manganese, antimony, selenium, and vanadium tend to concentrate on the smallest particle sizes and are collected less efficiently than the total particulates. For cadmium, lead and mercury there were not sufficient data for complete analysis, but their behavior should be similar to the other partially volatile elements.

Tables 8, 9, and 10 show the output distributions from the three control devices for Distribution III where the concentration of hazardous elements peaks at ∿5 μm. The mass distributions of total particulates and of arsenic and selenium are summarized in these tables for the outlet particulates in the third, seventh and eighth columns, respectively. The "average concentrations" at the bottom of each table when compared to the corresponding values found for their input in Table 3, show that arsenic and selenium concentrations in the bulk flyash have decreased. The distributions of emitted particulate arsenic and selenium shift to the smallest particle sizes just as in the case of Distribution I. The shift is not a significant one, but still, about 50% is on particles less than 3 μm in diameter.

Using available data(5) for trace elements, we calculated the removal efficiency of the trace elements having the concentration Distribution III. The results for the three control devices are summarized in Table 11. The more volatile trace elements for Distribution III are concentrated on the particle size range of 4 to 6 μm, a range much higher than the observed range for Distribution I. As a result of this change in the shape of the distribution, arsenic, chromium, antimony, selenium, and vanadium were removed more efficiently than the total particulates. This more efficient removal results from the increased efficiency of the control devices for larger particles sizes. In Tables 7 and 11, the

TABLE 7. Removal Efficiency for Trace Elements as Particulates and Total Particulates (Percent removal for Distribution I)

	Fabric Filtration	Electrostatic Precipitation	Venturi Scrubbing
TOTAL PARTICULATES -	98.7	99.5	99.1
Al	98.7	99.5	99.1
As	98.0	99.4	98.6
Ba	98.7	99.5	99.1
Br	98.4	99.4	98.9
Co	98.6	99.5	99.0
Cr	98.3	99.6	98.8
Cs	98.7	99.5	99.0
Eu	98.8	99.6	99.1
Fe	98.6	99.5	99.0
Hf	98.7	99.5	99.0
K	98.7	99.5	99.1
La	98.7	99.5	99.1
Mn	98.4	99.6	98.8
Na	98.7	99.5	99.1
Rb	98.6	99.5	99.0
Sc	98.7	99.5	99.1
Sb	98.2	99.6	98.8
Se	98.5	99.5	98.8
Sm	98.7	99.5	99.1
Sr	98.6	99.5	99.0
Ta	98.7	99.5	99.1
Tb	98.7	99.5	99.1
Th	98.8	99.5	99.2
Ti	98.7	99.5	99.0
V	98.5	99.6	98.9

TABLE 8. Distribution III - Fabric Filter

Particle Size (microns)	% Efficiency	g/SCF(a)	wt% of Particulates in Size Fraction	Conc. (μg/g)(b)		Weight Contribution (μg) of Size Fraction to Total		Percent of Total in Size Fraction	
				As	Se	As	Se	As	Se
<1	90	0.00034	44.2	89	5.0	39	2.2	26	26
1-2	95	0.00016	20.8	144	7.8	24	1.6	16	19
2-3	98	0.00009	11.7	200	10.6	23	1.2	15	14
3-4	99	0.00008	10.4	254	13.0	26	1.4	17	17
4-5	99.5	0.00007	9.1	304	15.4	28	1.4	18	17
5-6	99.9	0.00003	3.9	274	14.3	11	0.6	7	7
TOTALS		0.00077	100.1			151	8.4	99	100

Average Concentration 151×10^{-6} g As/g flyash — 8.4×10^{-6} g Se/g flyash

0.12×10^{-6} g As/SCF air — 0.006×10^{-6} g Se/SCF air

(a) Inlet distribution compiled from data in Reference 6.

(b) Determined from Figure 5 and Table 1.

Table 9. Distribution III - Electrostatic Precipitator

Particle Size (microns)	% Efficiency	g/SCF(a)	wt% of Particulates in Size Fraction	Conc. (μg/g)(b)		Weight Contribution (μg) of Size Fraction to Total		Percent of Total in Size Fraction	
				As	Se	As	Se	As	Se
<1	98.2	0.00006	21	89	5.0	19	1.1	9	10
1-2	98.2	0.00006	21	144	7.8	30	1.6	15	15
2-3	99.2	0.00004	14	200	10.6	28	1.5	14	14
3-4	99.6	0.00003	10	254	13.0	25	1.3	12	12
4-5	99.7	0.00005	17	304	15.4	52	2.6	26	25
5-6	99.8	0.00005	17	274	14.3	47	2.4	23	23
TOTALS		0.00029	100			201	10.5	99	99

Average Concentration 201 x 10^{-6} g As/g flyash — 10.5 x 10^{-6} g Se/g flyash

0.058 x 10^{-6} g As/SCF air — 0.003 x 10^{-6} g Se/SCF air

(a) Inlet distribution compiled from data in Reference 6.

(b) Determined from Figure 5 and Table 1.

TABLE 10. Distribution III - Venturi Scrubber

Particle Size (microns)	% Efficiency	g/SCF(a)	wt% of Particulates in Size Fraction	Conc. (μg/g)(b)		Weight Contribution (μg) of Size Fraction to Total		Percent of Total in Size Fraction	
				As	Se	As	Se	As	Se
<1	90	0.00023	41.2	89	5.0	37	2.1	21	23
1-2	94	0.00008	14.3	144	7.8	21	1.1	12	12
2-3	96	0.00007	12.5	200	10.6	25	1.3	15	14
3-4	97	0.00006	10.7	254	13.0	27	1.4	16	16
4-5	98	0.00006	10.7	304	15.4	32	1.6	19	18
5-6	99.5	0.00006	10.7	274	14.3	29	1.5	17	17
TOTALS		0.00056	100.1			171	9.0	100	100

	As	Se
Average Concentration	171×10^{-6} g As/g flyash	9.0×10^{-6} g Se/g flyash
	0.096×10^{-6} g As/SCF air	0.005×10^{-6} g Se/SCF air

(a) Inlet distribution compiled from data in Reference 6.

(b) Determined from Figure 5 and Table 1.

TABLE 11. Removal Efficiency for Trace Elements as Particulates and Total Particulates (Percent Removal for Distribution III)

	Fabric Filtration	Electrostatic Precipitation	Venturi Scrubbing
TOTAL PARTICULATES -	98.7	99.5	99.1
Al	98.7	99.5	99.1
As	99.2	99.6	99.4
Ba	99.0	99.6	99.3
Co	98.9	99.6	99.2
Cr	99.0	99.6	99.1
Cs	98.9	99.6	99.2
Eu	98.9	99.5	99.2
Fe	98.4	99.4	98.8
Hf	98.8	99.5	99.1
K	98.7	99.5	99.1
La	98.7	99.5	99.1
Mn	98.8	99.6	99.2
Na	98.7	99.5	99.1
Rb	98.7	99.5	99.1
Sc	98.7	99.5	99.1
Sb	99.1	99.6	99.3
Se	99.2	99.6	99.4
Sm	98.7	99.5	99.1
Sr	98.9	99.6	99.2
Ta	98.7	99.5	99.1
Tb	98.8	99.5	99.1
Th	98.9	99.5	99.2
Ti	98.8	99.5	99.1
V	99.0	99.6	99.2

overall removal efficiencies generally reflect the efficiency of each particular control device. These tables should not be used to critically compare one device with another. Instead, their purpose is to show their own relative capability on each trace element.

Comparing the removal efficiencies in Tables 7 and 11 of the partially volatile trace elements one finds that approximately twice as much material is emitted when particle size distribution peaks below 1 μm. The disparity between distribution shapes of total particulates and of hazardous trace elements must be taken into account when one considers control of trace element emissions by particulate removal techniques.

C. Gaseous Trace Element Emissions

Several trace elements are significantly volatilized during combustion of coal (see Table 12). Gaseous emissions are not efficiently trapped by fabric filtration of electrostatic precipitation. An advantage of Venturi scrubbing is that it serves to remove a fraction of the gaseous constituents as well as being an effective particle control technology. For example, the removal efficiency of Venturi scrubbing is about 50% for the gaseous sulfur oxides.(1) Since data are not available on the removal of other partially volatile trace elements, we have assumed that Venturi scrubbing removes about 50% of all gaseous forms of the hazardous trace elements. The 50% removal assumption should be a conservative one, since quenching effects and Venturi scrubbing would probably be more efficient for other volatilized trace elements than for sulfur oxides.

In the final impact statement(1) hydrogen selenide was suggested as the form of selenium in the flue gasses. Because of oxidizing conditions we feel that selenium should be in the oxide form. Also in the final impact statement(1) the removal efficiency of fluorides in the Venturi scrubbers is assumed to be 75%. We have arbitrarily used 50% for the reasons stated above. Certainly, further studies of removal efficiencies using Venturi scrubbing are needed for the partially volatile trace elements.

TABLE 12. Estimated Losses of Particulate and Gaseous Forms of Trace Elements from Coal Combustion (585,300 lb/hr)

Element	Average Coal[5,9] Composition (ppm)	Volatilization[9,10] (%)	Particulates Losses[a] (lb/day)	Gaseous Losses[b] (lb/day)
Ag	0.12	<10	0.02	<0.08
As	5	50	0.35	17.5
Be	1.2	<10	0.17	<0.84
Bi	5	30	0.49	10.5
Cd	0.2	50	0.02	0.72
Co	0.5	<10	0.07	<0.35
Cr	0.3	<20	0.04	<0.42
Cu	50	<10	7	<70
Fe	1500	<10	210	<1000
Ga	1.2	<10	0.17	<0.84
Ge	3	<10	0.42	<2.1
Hg	0.5	90[2,3]	0.07	3.2
Mo	10	50	0.07	35
Mn	50	<10	7	<35
Na	150	<10	21	<105
Ni	20	<20	2.2	<28
Pb	10	50	0.7	35
Rb	1	<10	0.14	<0.7
Sc	1	<10	0.14	<0.7
Sb	1	50	0.07	3.5
Se	1.5	50	0.11	5.3
Ta	0.3	<10	0.04	<0.21
Te	0.5	50	0.04	18
Th	1.5	<10	0.21	<1.0
Tl	0.1	50	0.006	0.33
V	10	<20	1.1	<14
W	1	<10	0.16	<0.70
Zn	15	<20	1.7	<21

(a) Estimated removal efficiency is 98%
(b) Estimated removal efficiency is 50%

D. Total Estimated Releases in Particulate and Gaseous Forms

Using a coal consumption rate of 585,300 lb/hr we have made an estimate of the trace element emissions from power plants. These emissions are based on a compilation of analyses of Western Coal(9) and Colstrip Coal.(11) In these calculations literature(2,3) and estimated(10) volatilization factors were used and it was assumed that 50% of the gaseous material was removed by Venturi scrubbing. The loss as particulates was derived by assuming a 1% emission (99% collection efficiency) of the nonvolatilized fraction escaped which seems to be a reasonable average based on the available control technology. The trace element emissions in units of pounds per day (Table 12) are for the particulate and gaseous forms of trace elements in coal.

The volatilized forms of the trace elements are probably short-lived since condensation presumably occurs rapidly in the presence of particulate matter at the ambient atmospheric temperature. It is very difficult to quantify the losses of volatilized elements, but the estimates given in Table 12 are probably the worst cases.

E. Conclusions and Summary

All three particulate control technologies considered in the assessment, fabric filtration, electrostatic precipitation, and Venturi scrubbing, are efficient in removing total particulates. For a coal consumption rate of 7000 tons/day and flyash collection efficiency of 99%, 0.35 lb of arsenic, 0.02 lb of cadmium, 1.2 lb of copper, 0.03 lb of mercury, 0.4 lb of lead, 0.07 lb of antimony, 0.11 lb selenium, and 1.1 lb of vanadium will be released as particulates each day. However, the losses may double if the hazardous trace elements on the escaping particulate material are concentrated on particle sizes less than 1 µm.

It is evident that more of each volatile element may escape in flue gasses as a volatile compound than as particulate material. Abatement of gaseous forms is poor for fabric filtration or electrostatic

precipitation. Venturi scrubbing reduces the levels of sulfur oxides by about 50% and is estimated to remove other hazardous volatile constituents by this amount. This appears to be a control technology preferable to fabric filtration and electrostatic precipitation. Based on the volatilization factors in Table 12 and 50% removal in the Venturi scrubbers, 17.5 lb of arsenic, 0.9 lb of cadmium, 12 lb of copper, 15 lb of fluoride, 1.3 lb of mercury, 19 lb of lead, 5.6 lb of selenium and 14 lb of vanadium could be released each day from a power plant with a daily coal consumption of 7000 tons. The actual gaseous release of these elements, especially fluoride, may be lower because the conservative estimate of 50% removal efficiency was chosen for Venturi scrubbing.

The gaseous emissions of hazardous volatile trace elements represent an area of concern because: 1) the actual firebox volatilization of the subsequent condensation and the chemical species involved are not well-known, and 2) losses to the environment of gaseous forms seem to be much larger than those by particulate material. This study does not consider potential problems which may be associated with disposal of the collected flyash. This problem should be investigated because trace elements in flyash may be in a mobile chemical state which can be readily leached by groundwater.

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